R.02-06-001

Third Report of Working Group 2 on Dynamic Tariff and Program Proposals: Addendum Modifying Previous Reports

January 16, 2003

California Public Utilities Commission Order Instituting Rulemaking on Policies and Practices for Advanced Metering, Demand Response, and Dynamic Pricing

TABLE OF CONTENTS

TABLE OF FIGURES

EXECUTIVE SUMMARY

In June 2002, the Commission expressed its interest in crafting a comprehensive policy that develops demand flexibility as a resource to enhance electric system reliability, reduce power purchase and individual consumer costs, and protect the environment. "Working Group 2" (WG 2) was established to address the specific issues concerning large customers (those whose average monthly demands exceed 200 kW). WG 2's mission was to develop a tariff or set of tariffs that expand demand response capabilities of large customers. In fulfilling this mission, WG 2 was further directed to pursue its best bet for a "quick win" and to develop full-scale tariffs or programs as opposed to pilots. Supplementing the mission were specific directives to WG 2 such as identifying dynamic pricing triggers, analyzing cost-effectiveness of the proposed tariffs, describing the necessary communication, metering and billing infrastructure, calculating program costs, and evaluating implementation issues.

On November 15, 2002, WG 2 issued its first report, which provided six proposals (four tariffs and two programs) that target large customers. The November 15 Report provides important details regarding the proposals such as how the tariffs/programs operate, the sources for their triggers, their intended levels of participation, and the amount of lead-time necessary to implement them. The November 15 Report also provides pertinent discussion concerning several fundamental considerations that affect tariffs/programs for large customers such as revenue neutrality and voluntary vs. mandatory participation. The November 15 Report also summarizes the state of knowledge based on existing dynamic tariffs within and outside California.

On December 13, 2002 WG 2 issued a second report that supplemented the information provided in the November 15 Report.[1] The second report provided detailed customer education and marketing plans, monitoring and evaluation plans, utility back-office capabilities and a cost-effectiveness analysis for each of the six proposals, as well as a discussion on potential pilot programs for large customers.

WG 2 now issues this third report and final report for consideration. It is intended to modify and or replace specific sections found in the November and December reports. Specifically this third report modifies some of the original tariff and program proposals made in the first report, and updates the customer education/marketing, cost recovery and cost-effectiveness assessments associated with the modified proposals.

[1] An errata report, dated December 23, 2002, was issued by WG 2 to correct errors in both the November 15 Report and the December 13 Report.

Reasons for the Modifications

As a result of feedback received at the December 4, 2002 Working Group 1 (WG1) meeting concerning the tariff and program proposals filed as part of the November 15, 2002 report, the three respondent utilities (PG&E, SCE, SDG&E) decided to make revisions to their proposals to attempt to satisfy WG1 expectations. On December 30, 2002, the utilities filed a joint proposal to withdraw certain tariff and program proposals and submit a new critical peak pricing (CPP) tariff proposal.

Further, in D.02-12-045, the Commission rejected about $29 million in funding required to implement the DWR/CPA Demand Reserves Partnership (DRP) program for inclusion in 2003 DWR requirement requirements. Simultaneous with DWR's appeal of this decision through an Application for Rehearing, the CPA decided that some minor modifications to its DRP program would be advisable to increase likely participation rates and aggregate capacity of load reduction potential.

Both of these changes stem from desires by sponsors of WG2 participants to create (or modify existing) programs to achieve substantial levels of demand reduction by summer 2003, thus satisfying "quick win" objectives.

WG 2 met on January 10, 2003 to further explore and discuss the changes proposed by the UDCs and the CPA. The meeting was held to provide WG 2 participants an opportunity to seek clarification and provide feedback. At that meeting additional program modifications were proposed by WG 2 participants. These are described further in this report.

Summary of the Proposed Modifications

PG&E, SCE and SDG&E's (Joint Utilities) Critical Peak Pricing (CPP) proposal modifies and replaces both PG&E's original CPP rate proposal and SCE's RTP-MI proposal presented in the first WG2 report. SDG&E already has a CPP tariff in place, but has agreed to modify its existing program to correspond with the parameters below to promote a consistent statewide CPP program.

According to the Joint Utilities, this latest proposal is designed to create a CPP program that is more attractive for customers with large air conditioning loads, including commercial office buildings. It is based upon a conventional three period time-of-use rate, but incorporates two pricing levels for on-peak and part-peak electric usage. The CPP proposal is designed to be revenue-neutral within each applicable customer class during the summer months.

The CPA has modified its Demand Reserves Partnership (DRP) by proposing to increase the incentives paid to participants as well as making changes to its marketing effort.

Some parties believe that some specific proposals will not lead to high levels of customer participation. These parties propose additional incentives to increase participation. Other parties believe that allowing customers to participate in more than one program can increase participation.

Purpose of This Report

This is the third of three reports provided by WG 2 in accordance with its mission and the directives provided to date. The purpose of this report is to modify the information provided in the November 15 and December 13 Reports[2] so that Working Group 1 has a complete picture of the tariffs and programs now proposed by WG 2 participants in fulfillment of its mission. The two original reports (as corrected by the errata report) and this addendum report should be considered as a body by decision-makers as WG 2 believes that the information contained in all three reports is relevant.

This third report was not written by a single individual or organization but is the collective product of several participants in WG 2. (See Appendix B for the List of Authors.) Drafts of each chapter in this report have been circulated among the participants of WG 2 prior to its publication in order to incorporate feedback.

In contrast to the November 15 report, and only because of the limited timeframe available to prepare this report, participants did not have an opportunity to submit alternate viewpoints concerning facts, assumptions, analyses or conclusions. The absence of alternate viewpoints should not be understood as agreement, or that consensus exists. Rather than using this opportunity to insert alternative viewpoints, WG2 participants thought it best to simply file their comments on all three WG 2 reports on approximately January 27, 2003.

[2] An errata report that corrects both the November 15 and December 13 Reports was distributed to WG 2 and the service list on December 23, 2002.

I. INTRODUCTION

On June 6, 2002, the Commission adopted R.02-06-001, its Order Instituting Rulemaking on "policies and practices for advanced metering, demand response, and dynamic pricing." In the Administrative Law Judge's Ruling Following Prehearing Conference, dated August 1, 2002, a procedural framework was established. This framework includes three working groups: WG1 Overall Policy, WG2 Large Customer Issues, and WG3 Small Customer Issues. "Large Customer" is defined as a customer with average monthly demands of 200 kW or greater[3].

This is the third of three reports issued by WG2. The first report, issued on November 15, 2002, provides detailed descriptions of four tariffs and two programs that target large customers. The second report, issued on December 13, 2002, addresses specific implementation issues such as marketing and customer education plans, monitoring and evaluation plans, range of impacts as well as a cost-effectiveness analysis for the tariffs and programs proposed in the first report. This report modifies some of the original tariff and program proposals made in the first report, and updates the customer education/marketing, cost recovery and cost-effectiveness assessments associated with the modified proposals.

This report includes the following general sections:

- a revision of some of the package of tariff and program proposals in the November 15 report,
- a limited update of the specific marketing and customer education plans in light of these new tariff and program proposals,
- a revised cost-effectiveness analysis,
- an update of cost recovery issues

The remainder of this Introduction provides a more detailed description of the mission of WG2, the nature of the WG2 process, and the role of this report.

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[3] The ALJ Ruling definition differs from the definition included in the contracts between the CEC and the utilities. In those contracts, the "End-Use Customer" is defined as "using, on average over the course of a calendar year, more than 200kW of electric energy and power per calendar day. . ." The differences between these definitions point to a need to who precisely should receive RTP metering systems. In the proposals submitted to WG1 UDCs express willingness to extend tariffs proposed in the WG2 reports to smaller customers provided certain cost recovery conditions are satisfied.

I.A. Mission for >200 kW Customers

The mission for WG2 was defined as: "Expanding demand response capabilities by developing a tariff or set of tariffs to be used for large customers with average monthly demands of 200 kW and above."[4]
In fulfilling this mission, WG2 was further directed to pursue its best bet for a "quick win" and to develop full-scale tariffs or programs as opposed to pilots.

As a result of feedback received at the December 4, 2002 Working Group 1 meeting concerning the tariff and program proposals filed as part of the November 15, 2002 report, the three UDCs decided to make revisions to their proposals to attempt to satisfy WG1 expectations. On December 30, 2002, the UDCs filed a joint proposal to withdraw certain tariff and program proposals and submit a new critical peak pricing (CPP) tariff proposal.

Further, in D.02-12-045, the Commission rejected about $29 million in funding required to implement the DWR/CPA Demand Reserves Partnership (DRP) program for inclusion in 2003 DWR requirement requirements. Simultaneous with DWR's appeal of this decision through an Application for Rehearing, the CPA decided that some minor modifications to its DRP program would be advisable to increase likely participation rates and aggregate capacity of load reduction potential.

Both of these changes stem from desires by sponsors of WG2 participants to create (or modify existing) programs to achieve substantial levels of demand reduction by summer 2003, thus satisfying "quick win" objectives.

WG 2 met on January 10, 2003 to further explore and discuss the changes proposed by the UDCs and the CPA. The meeting was held to provide WG 2 participants an opportunity to seek clarification and provide feedback. At that meeting additional program modifications were proposed by WG 2 participants. These are described further in this report. The January 10 meeting also reviewed the results of the revised cost-effectiveness analysis that incorporates the UDC's proposal. This report provides the revised cost-effectiveness analysis that also reflects the group discussion on January 10.

I.B. Nature of the Working Group Process

In addition to conducting the specific activities described and in the first two WG2 reports, WG 2 was established as the forum where stakeholders could exchange information and viewpoints, deliberate on the issues, and attempt to develop consensus while pursing their preferred solutions. WG 2 represented a diversity of interests in demand response issues for large customers: investor-owned utilities, municipal utilities, large customer associations, ratepayer advocates,

[4] August 1 ALJ Ruling, pg. 4

various demand response vendors and consultants, energy service providers, utility workers, and the California Independent System Operator. Staff from the California Power Authority, the California Energy Commission, and the California Public Utilities Commission served as facilitators for WG2.

WG 2 met nearly every week, starting on September 18, 2002 for a total of 12 meetings.[5] All meetings were open to the public and were noticed as workshops in the Commission's Daily Calendar as well as on the Commission's website. Meeting agendas were made publicly available 48 hours prior to each meeting, and minutes for each meeting were drafted and circulated to all participants. Copies of the minutes for the first eight meetings were provided in Appendix B of the Nov. 15 Report. Copies of the minutes for the next three meetings were provided in Appendix B of the December 13 report. Copies of the minutes of the January 10, 2003 meeting are provided Appendix A of this report.

The intent of the Working Group process was to develop the broadest support possible for specific demand response tariffs or programs for large customers. The meetings were facilitated[6] in a workshop format where stakeholders were encouraged to make proposals, provide their opinions, share their experience, and deliberate on issues. Participants also made presentations, provided handouts and materials for review, and answered questions from others. While the intent of the Working Group process was to develop consensus around a set of proposals, participants in the group carried a diversity of opinion on a number of issues and there were struggles to find common ground in terms of what can be a 'quick win'. See the November 15 Report for more details concerning the nature of the Working Group process and how the process influenced the development of the tariff and program proposals put forward by WG 2.

I.C. Role of this Report

The mission of WG 2 is to develop a tariff or set of tariffs for customers with demands greater than 200 kW with the goal of expanding demand response capabilities. The role of this report is to modify the information provided in the November 15 and December 13 Reports[7] so that Working Group 1 has a complete picture of the tariffs and programs now proposed by WG 2 participants in fulfillment of its mission. The two original reports (as corrected by the errata report) and this addendum report should be considered as a body by decision-makers as WG 2 believes that the information contained in all three reports is relevant.

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[5] Specific dates of the Working Group 2 meetings were: September 18, 26, October 2, 11, 17, 23, November 1, 12, 19, December 3 ,10, 2002, and January 10, 2003.

[6] Mike Jaske of the California Energy Commission served as the Working Group facilitator for each meeting. Bruce Kaneshiro of the CPUC Energy Division prepared meeting notes and David Hungerford of the CEC assembled the report.

[7] An errata report that corrects both the November 15 and December 13 Reports was distributed to WG 2 and the service list on December 23, 2002.

In the sections of this report, three different styles have been followed. In some instances, a section in this report has the same scope of a section in one of the previous two WG2 reports, and the section in this report replaces the comparable section in one of the previous reports in its entirety. In other cases, sections of this report make modest changes to a previous section and only changed sentiments are reported. Finally, in a few instances sections of this report are entirely new and add to, rather than replacing or modifying, sections of either of the two previous reports. The role of each section is clearly labeled.

Like the November 15 and December 13 reports, this report was not written by a single individual or organization but is the collective product of several participants in WG 2 (see Appendix B for the list of authors). Drafts of each chapter in this report have been circulated among the participants of WG 2 prior to its publication in order to incorporate feedback.

In contrast to the November 15 report, and only because of the limited timeframe available to prepare this report, participants did not have an opportunity to submit alternate viewpoints concerning facts, assumptions, analyses or conclusions. The absence of alternate viewpoints should not be understood as agreement, or that consensus exists. Rather than using this opportunity to insert alternative viewpoints, WG2 participants thought it best to simply file their comments on all three WG 2 reports on approximately January 27, 2003.

II. MODIFICATIONS TO PROPOSALS

II.A. Withdrawal of Prior Proposals

SCE MODIFICATIONS TO PROPOSALS

II.A.(1).a. SCE's Withdrawal of its Real-Time Pricing Market Index Proposal and Re-instatement of its Demand Bidding Proposal

In SCE's December 30th Addendum to the Working Group 2 Report, SCE withdrew its Real-Time Pricing Market Index and Demand Bidding proposals in order to more effectively focus resources towards development of a new statewide Critical Peak Pricing proposal, which may offer greater potential for encouraging customer participation. Both the RTP and DBP modification initially proposed by SCE relied exclusively on the availability of a transparent real time energy market which does not exist today but is expected to be developed and implemented by the ISO in the near future. In addition, both of these tariff proposals did not fully leverage the metering infrastructure now available to customers in the 200 kW to 500 kW range.

In addition, initial findings from customer focus groups hosted by SCE in mid-December indicated a preference for a more simple CPP tariff design rather than market based price signals. However, focus group results did find some customers, particularly larger customers (500kW and above), that were interested in participating or continuing to participate in a market-triggered Demand Bidding program. At the WG2 meeting held on January 10th, customer representatives expressed support for SCE's withdrawal of its Real-time Pricing Market Index proposal. However, they were concerned that SCE was dropping its DBP proposal. At that meeting SCE clarified its position that we fully support continuation of the existing reliability based demand bidding program and are committed to development and rollout of a market based DBP program when a market is fully established. SCE believes that a market-triggered Demand Bidding program will ultimately serve as a useful program that could be better integrated into the UDC procurement process

After consultation with the UDC's, SCE finds that its proposal is entirely consistent with the other UDC demand bidding proposals in that all UDC's are committed to refining a market based program **after** a market is fully established. SCE believes that a market-triggered Demand Bidding program will ultimately serve as a useful program that could be better integrated into the UDC procurement process. Once the ISO's day-ahead market has been established, this market would serve as the basis for triggering this program. Thus, even though a market based Demand Bidding program would not begin until the ISO day-ahead market is operational, SCE is requesting Commission approval for this program in the Phase I Decision.

Accordingly, for Phase 1, SCE now, once again, endorses the statewide Demand Bidding proposal in addition to the new statewide Critical Peak Pricing proposal. SCE confirms its earlier withdrawal of its Real-time Pricing Market Index proposal.

JOINT UTILITIES DEMAND BIDDING PROGRAM PROPOSAL

PG&E's submittal of the Joint Utilities Demand Bidding Program Proposal remains unchanged. The Demand Bidding Program has a price trigger and a system emergency trigger. PG&E will be ready to implement the price trigger portion of the Demand Bidding Program Proposal when the California Independent System Operator (CAISO) day-ahead market has been established and they begin to post day-ahead market prices.

PG&E WITHDRAWAL OF RTP/CPP PROPOSAL

PG&E's original RTP/CPP program proposal served as the basis for the new statewide Joint UDC CPP proposal, which is essentially a simplified version of the original PG&E proposal, modified in such a way as to make it most suitable for statewide implementation. Therefore, PG&E is withdrawing its original RTP/CPP program proposal in order to join the other two UDCs in recommending the Joint UDC CPP proposal as a common statewide program.

II.B. Joint UDC CPP Tariff Proposal

The following description of a joint UDC CPP proposal is substantially the same as was submitted by the UDCs on December 30, 2002.

GENERAL DESCRIPTION

PG&E, SCE and SDG&E's (Joint Utilities) Critical Peak Pricing (CPP) proposal modifies and replaces both PG&E's original CPP rate proposal and SCE's RTP-MI proposal presented in the first WG2 report. SDG&E has already implemented a previously-authorized critical peak tariff (Schedule ALTOU-CPP) that was designed to meet different objectives than those intended for the Joint Utilities' CPP program. SDG&E will continue to maintain this previously authorized tariff, while joining the other two utilities in implementing the new statewide CPP.

This joint proposal is designed to create a CPP program that is more attractive for customers with large air conditioning loads, including commercial office buildings. It is based upon a conventional three period time-of-use rate, but incorporates two pricing levels for on-peak and part-peak electric usage. The CPP proposal is designed to be revenue-neutral within each applicable customer class during the summer months (i.e., a customer might pay more on its monthly bill than under the standard tariff during some billing cycles, but less in others).

Specific features of the CPP rate are:

- Offered to customers with demands of greater than 200kW; most of these customers will already be equipped with appropriate interval meters as a result of Assembly Bill 29X (AB1x29).
- Offered during the summer peak season (as defined in each utility's currently applicable tariffs).
- Critical peaks will have two pricing levels, one for on-peak and one for the part-peak electric usage.
- Fixed number of CPP operating days (e.g., maximum of 15 CPP days and a minimum of 5 CPP days, with rates designed based on assumption of a fixed number of CPP days as specified in final Phase 1 decision).
- High-price CPP days to be communicated to customers on a day-ahead basis.
- CPP days generally to be selected on the basis of forecasted utility-specific weather conditions within pre-determined zones.

The proposed pricing parameters are as follows:

- For usage between 3:00 and 6:00 p.m. on a CPP day, critical peak prices to be set at level equivalent to five (5) times the utility's specific otherwise-applicable total on-peak energy charge (that period most closely corresponds to the statewide system peak), and

- For usage during the periods between 12 Noon and 3:00 PM and between 6:00pm and 7:00 PM on a CPP day, critical peak prices to be set a level equivalent to three (3) times the utility's specific otherwise-applicable total partial peak energy charge.
- Excess revenue amounts that would be generated by CPP rates on program operating days will be used to discount on-peak and part-peak energy charges on non-CPP operating dates, such that rates are revenue neutral in comparison to each otherwise-applicable rate schedule. Revenue neutral in this case will mean that if an average usage level customer was on this rate, and did not respond by reducing demand during the called critical peak periods, the customer will pay the same total bill, or same average rate, as if they had been on the default tariff.

The Joint Utilities believe that a final Phase I decision embracing this set of basic design recommendations would provide the foundation for ready implementation of a statewide CPP program for operation during the summers of 2003 and 2004.

ELIGIBILITY

This program would be offered and available to all large bundled service customers (those with at least 200 kW of maximum demand) currently served on PG&E's electric rate Schedules A-10-TOU, E-19, E-20 and E-37, SCE's electric rate Schedules GS-2, TOU-GS-2, and TOU-8,[8] and SDG&E's electric rate Schedule AL-TOU.[9]

Participants are required to have an interval meter and internet access to their respective utility's web-based notification system. However, nearly all of these customers have already received the interval meters that would be needed to participate through last year's AB1x29 metering program. Any additional equipment needed to notify customer's one day in advance of a pending CPP operating day would be relatively modest.

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[8] In its December 30th Addendum to the Working Group 2 Report, SCE stated its intention to limit applicability of the statewide CPP proposal to mid-sized customers with load between 200kW and 500kW. SCE's rationale for doing so was to focus primarily on a largely "untapped" market segment with respect to demand response programs. (Customers with load 500kW and above largely have already responded by participating in other existing programs and thus, this market segment may already be fairly saturated with respect to its ability to shift additional load or reduce peak usage.) **However, in an effort to be consistent with the other utilities and to maximize the potential to achieve widespread demand response, SCE now proposes to extend its participation the statewide Critical Peak Pricing tariff to all customers with demand above 200 kW**.

[9] SDG&E customers with demands above 300kW received AB1x29 meters. However, essentially all SDG&E commercial customers 20kW and greater are on rate schedule AL-TOU/EECC. SDG&E recommends that all customers on AL-TOU be eligible for the CPP rate and that additional metering costs be recovered under the WG2 Cost Recovery Mechanism.

This program would not be available to those currently participating in an existing load reduction program that would result in double incentive payments to the customer.

SOURCE OF DRIVERS/TRIGGERS

Participants would be notified of the applicable pricing levels on a day-ahead basis, with the higher-cost CPP operating days to be selected initially on the basis of utility-specific weather conditions (although an additional, more electricity cost based factor could be considered when accurate real-time energy pricing information becomes available on a regular basis). The Joint Utilities will designate up to two or three separate climatic zones within their respective service territories.[10] A specific forecasted temperature, at a particular location within each zone, will be selected as the CPP implementation trigger for that zone and will be included in the CPP tariffs, together with appropriate rules for ratcheting the temperature-based triggers up or down as necessary to ration the assigned number of CPP days over the course of the summer.[11] Participants would be able to generally plan for and expect that the highest price signals will be applied on the warmest summer weekdays. Similarly, if weather forecasts call for an extended "heat wave," customers might expect these critical price signals to continue for two or more consecutive days.

INTENDED LEVEL OF PARTICIPATION

Setting aside customers who are already participating in each utility's load reduction programs, this customer group accounts for approximately 6250 MW of aggregate commercial air-conditioning load on typical summer peak days.

The Joint Utilities recommend that this program be implemented on a voluntary basis, and believe that approximately 930 MW (PG&E - 430 MW, SDG&E 70 MW, and SCE - 430 MW) of enrolled load (representing a respective participation rate of 15 % for each utility) is a conservative upper bound on the number of customers and amount of load that could be successfully recruited to participate in this program.[12] If the participating customers contribute an average of 15%

[10] At the WG 2 meeting of January 10, 2003, representatives attending for the City and County of San Francisco (CCSF) described their goals for achieving new demand reductions targeted to reduce loads in San Francisco and on the S.F. Peninsula. PG&E will designate one climate zone for San Francisco and the S.F. Peninsula in order to assist CCSF in these targeted demand reduction efforts.

[11] The Joint Utilities have not recommended a specific number of CPP days as the design basis for the CPP rate, but invite comments on this design parameter from interested parties and will look to the final Phase 1 decision to establish a specific number. However, the cost-effectiveness analysis summarized in Section IV of this Addendum Report was carried out using a design basis of 12 CPP operating days.

[12] This would translate to between 940 and 1310 customers at SCE and PG&E, and between 200 and 280 customers at SDG&E.

load reductions across all of the high-price CPP operating days, this would result in 140 MW of new statewide demand response capability. The 15% reduction figure represents lowered energy demands as a result of a reduction or shifting in commercial air-conditioning load requirements. (When combined with existing programs and other programs being developed, the Joint Utilities expect that this total package of options will provide the state with significant load reduction resources.)

Initial customer focus group analysis conducted by SCE and additional discussions with interested customer group representatives indicate that the 930 MW participation level may be difficult to reach. The Joint Utilities will look to the WG1 principals to determine if additional incentives are appropriate, and if so, what incentive types might be reasonable to encourage greater participation. Examples of possible alternatives for such additional CPP participation incentives have been put forth by CCEA and are described in Section II.C.1 of this report. All parties are invited to comment on the appropriateness of such incentives in their comments to be submitted on January 27, 2003.

SOURCES/LEVELS OF COSTS

The Joint Utilities would incur a certain amount of one-time incremental start-up costs to implement this program, largely for metering, billing system modifications (e.g., programming, account set-up, account maintenance, testing, data retrieval and preparation) and customer recruitment. The estimated statewide program implementation costs for 2003 are currently estimated to be $4.2 million ($2.5 million – PG&E; $1.0 million – SCE; and $0.7 million – SDG&E. After 2003, ongoing statewide implementation costs are estimated to be $2.1 million per year. Final estimates for these cost categories will be described by each of the Joint Utilities in their filed comments on January 27, 2003, consistent with the program administration, marketing and customer education considerations described in Section III of this report.

In addition to the one-time start-up costs, two different kinds of revenue shortfall costs will need to be considered for new demand reduction programs: (1) the “structural” or “self-selection” savings that may occur because some customers will always be able to benefit under a new rate option, without actively modifying their loads (even when the underlying rate design is revenue-neutral on a class average basis), and (2) the “dynamic” bill savings that result when customers do change their loads in response to the new prices. Under the proposed revenue-neutral design, these two later costs are not incurred directly by the Joint Utilities, but they do play into the cost effectiveness of the program and the allocation of costs within the respective rate classes.

This proposal does not include any of those costs pertaining to incentives beyond those provided in the program’s revenue neutral rate design. Additional incentive costs may be incurred and require recovery if the CPUC later decides that other incentives are necessary to increase participation in this program

METHOD OF COST RECOVERY

The Joint Utilities propose that a balancing account be established to track the incremental one-time "set-up" and on-going costs related to billing system modifications and customer recruitment per the "Cost Recovery" Section in the WG2 report. This approach will leave a good deal of flexibility as the final demand response programs are designed and implemented for the larger customers.

The Joint Utilities believe that its current balancing account mechanisms are adequate for recovery of the customer bill savings that will result if this program proposal is implemented. If the program is successful, the utilities would expect the revenue reductions associated with both customer self-selection and dynamic bill savings to be somewhat offset by changes in the quantity and/or types of procurement products or spot market purchases that will need to be made on behalf of all customers. (If the program does not prove to be successful, it should not be extended for future years.)

For PG&E, the current Emergency Procurement Surcharge Balancing Account (ESPBA) and the Transition Revenue Accounting (TRA) mechanisms record the actual costs of procurement products and spot market products. Additionally, the current TRA mechanism ensures that full collection of PG&E's authorized distribution, nuclear decommissioning, and public purpose program revenue requirements will continue even if changes in usage patterns from demand response programs produce revenue under-collections of the type described here. PG&E will seek similar accounting mechanisms once the TRA is no longer in place.

For SCE, the current Settlement Rates Balancing Account (SRBA), and the Procurement Related Obligations Account (PROACT) mechanism records Recoverable Costs against revenues, so that any shortfalls will work to reduce recorded Surplus. SCE anticipates that the PROACT will be recovered by the middle of 2003, and that the shortfalls that result from this program will not be material. SCE will be filing an application to propose both rates and ratemaking mechanisms that will go into place, after the PROACT is fully recovered. SCE will provide an update to Working Group 1 after filing its Post-PROACT ratemaking proposal as to how cost recovery will work in its post PROACT accounting.

SDG&E's current Energy Resource Recovery Account (ERRA) covers any energy commodity shortfall that may occur due to reductions in demand resulting from CPP. SDG&E does not anticipate a material impact on transmission and distribution revenue requirements due to the CPP optional rate available to SDG&E AL-TOU beginning Summer 2003. If the CPP optional rate design is expanded to a wider "default" rate basis, then SDG&E will need to reevaluate the impact on of the CPP on SDG&E transmission and distribution revenue requirements.

LINKAGE TO PROCUREMENT ACTIVITIES

As noted above, if the program is successful, the Joint Utilities would expect the revenue reductions associated with customer bill savings to be offset to some degree (more or less depending on market prices) by changes in the quantity and/or types of procurement products or spot market purchases that will need to be made on behalf of all customers.

ESTIMATED START DATE

The Joint Utilities proposal is for CPP rates to be effective beginning June 1, 2003. Delay beyond a June 1, 2003 starting date could detract from successful implementation of the program this summer.

PROPOSED METHOD OF IMPLEMENTATION

Participating customers in Summer 2003 will be requested to provide information on measures they took to reduce demand, and provide operating information on the impact of building residents. The Joint Utilities anticipate that most of the demand reductions will result from reduced lighting and air-conditioning load when Critical Period events are called. Customer site data will be used to identify the most effective methods for customer response, both from a utility perspective and a customer perspective, and to prepare educational and to further market the viability of the program.

The Joint Utilities will be working to establish protocols for monitoring customer sites, to review how demand reductions are achieved, to record changes in building temperature, impact on employees and residents in office buildings, etc.

LEAD TIME FROM APPROVAL

Provided that a final Phase 1 decision and complete rate design are in place by early March, the Joint Utilities believe there will still remain adequate time during the spring of 2003 to educate customers and recruit participants for the June 1 start date. However, the Joint Utilities believe that at least 90 days will be needed between the final Phase 1 decision and the starting date of the Summer 2003 program for those customer recruitment and education activities and billing system modifications necessary for successful program implementation.

II.C. CPA DRP Proposal

The following description is substantially the same as the DRP Proposal description in section V.F in the November 15, 2002 WG2 Report.

GENERAL DESCRIPTION

The California Power Authority (CPA) is using load reduction by end users to provide Demand Reserves in the wholesale market. The Demand Reserves can be used in 2 ways:

Ancillary Services – as 10 minute response non-spinning reserves or 60 minute response replacement reserves in the ISO markets, and
Call Option – as energy supplied in the ISO Day Ahead, Hour Ahead or Supplementary Energy markets during high wholesale market price or critical demand times.

CPA contracts with Demand Reserve Providers to work with end users and be contractually responsible for delivering the load reduction when called. Demand reduction for individual end users is limited to 11 am to 7 PM, Monday to Friday for 24 hours per month or 150 hours per year.

CPA has signed a Participating Load Agreement with the ISO to abide by the ISO's rules for load reduction to be used as supply in the ISO wholesale markets.

Two different types of baselines are used to compute load reduction. First, for delivery into the ISO real-time market by participating in the Ancillary Services or Supplemental Energy markets, the baseline is the ISO prescribed baseline – the load level in the interval (10 minute for non-spin and 60 minute for replacement and supplemental) before notification. Second, for the Call Options delivered into the ISO Day Ahead or Hour Ahead markets, the baseline is a load shape computed from the previous 10 business days, but calibrated to the load level for the three hours before notification. Businesses with temperature-sensitive or dynamic load levels would prefer delivery into the Hour Ahead or real-time markets for a baseline calibrated to that day's usage.

The baseline for incremental energy usage under the ISO Decremental Credit option is discussed under "(5) Sources/Levels of Cost" below.

ELIGIBILITY

Any end users (bundled service or direct access) of the Investor-Owned Utilities would be eligible to participate in this program. In addition, end users of cooperating load serving entities in California can also participate.

SOURCE OF DRIVERS/TRIGGERS

The IOU who buys the reserves determines whether to use it as a Call Option or in the Ancillary Services market. If it is used as a Call Option, the procuring IOU will select the hours to dispatch the load reduction. Typically, with an $80/MWH strike price, the IOU would dispatch this only when the spot market price exceeds $80.

If the IOU schedules the Demand Reserves as Ancillary Services or Supplemental Energy with the ISO, then the ISO dispatches the Demand Reserves along with other resources based on the energy bid price. End users in the Ancillary Services market can request a contingency reserve status which means they will not be dispatched until all other economic resources have been dispatched.

INTENDED LEVEL OF PARTICIPATION

CPA has had end users (or their direct agents) express a bona fide interest in providing 500 MW of load reduction in this program. Depending on how quickly the uncertainty of cost recovery is resolved, CPA expects one quarter to one half of that potential (125-250 MW) to materialize for the summer of 2003.

SOURCES/LEVELS OF COST

The IOU contracts with CPA to provide the Demand Reserves directly (or currently indirectly through DWR) just like if it were buying peaking capacity. CPA in turn pays the Demand Reserve Provider who compensates the end user for the demand reduction.

CPA will pay the Demand Reserve Provider for demand reduction that can respond within:

- 10 minutes and qualify to participate in the non-spin Ancillary Services market, $64[13]/kW-yr and $.08/kWh;
- 60 minutes as a Call Option is paid $47[14]/kW-yr and $.08/kWh;
- 60 minutes to participate in the ISO supplemental energy market, whatever energy price is bid when selected by the ISO;

In addition, for the transmission pilot in transmission constrained areas (e.g., San Francisco Bay Area and San Diego), an additional capacity payment of $20/kw-yr will be paid.

Per end users request, the CPA proposes an augmentation in which the IOUs will pay for incremental consumption of bundled service end users on firm service:

$.02/kWh whenever the ISO decremental real-time price is less than or equal to $.03/kWh but greater than $.015, and
$.035/kWh whenever the ISO decremental real-time price is less than or equal to $.015/kWh.

Moreover, the IOUs will pay for incremental consumption of bundled service end users on *non-firm* service:

$.01/kWh whenever the ISO decremental real-time price is less than or equal to $.03/kWh but greater than $.015, and
$.025/kWh whenever the ISO decremental real-time price is less than or equal to $.015/kWh.

Incremental consumption is defined as:

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[13] $51 if the customer is also participating on a Critical Peak Pricing or Real-Time Pricing program.

[14] $36 if the customer is also participating on a Critical Peak Pricing or Real-Time Pricing program

(Actual consumption that hour)
minus
(Average consumption during that time period (e.g., peak, partial, off-peak) for the same billing month in 2002)

The credits reflect that the generation component (excluding surcharges) of the energy charge in the appropriate retail rates ranges from $.04-.07/kWh. When the ISO price is significantly lower than these prices, the IOU incremental costs are lower – these credits incent incremental usage to be directed to such hours.

To implement the Call Option and ISO Decremental Energy Credit, no substantial changes are anticipated in the IOU processes. However, to implement the Ancillary Services and Supplementary Energy markets, the IOUs will need to put such load on a separate ISO Resource ID. This will have cost consequences in the managing of meter data and settlements. CPA is working with the IOUs and ISO to identify the incremental costs of this capability, which will become increasingly important anyway in the new wholesale market structure, with the increased emphasis on Demand Response.

As described in section III.B.(2) there are some incremental software costs and incremental operating costs for the utilities and some incremental administrative costs for CPA in marketing and supporting these programs. In addition, incremental CEC meters are proposed.

METHOD OF COST RECOVERY

This is mostly a commodity procurement cost for the IOU just like any other peaking capacity contract purchase. Hence, most of CPA's costs will be recovered through the commodity cost recovery, either through DWR or through a contract directly with the IOUs.

PUC Decision.02-12-045 struck the funding for the DRP from DWR's revenue requirement. DWR has appealed that decision and it is scheduled to be reconsidered by the PUC. If Decision 02-12-045 is upheld, then CPA will proceed to execute procurement contracts directly with the IOUs by the end of March with price and operational terms comparable to those of the DWR contract. This is consistent with PUC Procurement Decision 02-10-062.

CPA and the utilities have some other incremental administrative and capital costs, as noted above and elaborated in section IIIB. The utility costs will be recovered using the utilities proposed mechanisms for recovering administrative and capital costs. CPA's costs will be recovered with an IOU contract in adjunct to the procurement contract.

LINKAGE TO PROCUREMENT ACTIVITIES

Per the PUC Procurement Decision (D02-10-062) and presumably refined in this Rulemaking, the IOU will include this as a resource in its procurement plans similar to any other energy limited peaking resource.

ESTIMATED START DATE

The program's operations from 2002 have been suspended pending resolution of the cost recovery. It is expected to significantly ramp up in June 2003 assuming a full PUC's decision in this rulemaking in March.

PROPOSED METHOD OF IMPLEMENTATION

This program will be implemented using the infrastructure of the CPA Demand Reserves Partnership. To execute the transmission pilot, interaction with the ISO and local IOU will be necessary to define and execute the appropriate triggers to reflect pending transmission constraints.

LEAD TIME FROM APPROVAL

Little operational lead-time is required for the core program since we will use the existing infrastructure. Some coordination with the IOU dispatchers is necessary to transfer that function from DWR. However, there can be several months lead time to help additional end users participate. A couple months lead-time should also be allowed for the implementation issues concerning the transmission pilot.

OTHER IMPLEMENTATION ISSUES

Working Group 1 has expressed a willingness to entertain increased incentives to encourage greater participation. CPA proposes accomplishing that in three ways. First, CEC meters should be made available to end users eligible for this program but not already having CEC meters. Second, bundled service customers should be allowed to participate in the DRP and on a Critical Peak Pricing or Real-Time Pricing program. Third, if not participating on multiple programs, customers should receive an increased incentive, as described in section (3) above.

Consistent with the proposal for multiple program participation in Section II.D.(2), CPA outlines below how customers could participate on the Demand Reserves Partnership and other programs, especially any applicable Critical Peak Pricing or Real-Time Pricing rate. DRP participants, however, would only receive a capacity payment and not an energy payment from CPA. This is similar to how interruptible or reservation payment programs have been implemented in other areas with two-part RTP.

II.D. Other Revised Proposals

The additional proposals contained in this section are new and are not contained in either of the previous WG2 reports.

Some parties believe that some specific proposals will not lead to high levels of customer participation. These parties propose additional incentives to increase participation. Other parties believe that participation can be increased by allowing customers to participate in more than one program. Both of these suggestions are explained in this section.

CUSTOMER INCENTIVES AND RISK MANAGEMENT PROPOSAL (CCEA)

Customers going on critical peak pricing have no experience with the rate and face the risk of paying a higher bill. For example, even if a customer knows his or her historical peak to off-peak usage ratio, the customer still would not know when critical peak events will occur and, therefore, what their usage during such events will be. The uncertainty is particularly high in the first summer of the program, since there is no operating history. The purpose of this proposal is to overcome customer reluctance to participate by managing the risks without creating excessive incentives that diminish the long-term cost-effectiveness of the tariff compared to supply-side alternatives.[15]

The proposal is to provide two incentive/risk management options for customers. Customers may select Option A or Option B but not both. Participation in both options is capped to control program expenditures. Cost recovery for these options is proposed to be accounted for as electric commodity payments and be handled in the utilities' electric commodity balancing accounts (see joint utilities CPP proposal, Method of Cost Recovery section, for details on method of cost recovery via these balancing accounts).

II.D.(1).a. Option A: First Summer Trial Period

With this option, at the end of the first summer, the customer's aggregate CPP bill for the summer months would be compared with the customer's bill on his otherwise applicable tariff. If the CPP bill is higher, the customer will receive a reimbursement for 90 percent of the difference. The level of 90 percent is proposed so as to minimize, but not eliminate risk. Because some risk remains, only customers who have some expectation of reducing peak load should join the program.

Option A would be capped at a maximum participation of 930 MW statewide (the total program participation level discussed in the Joint Utility proposal). The estimated exposure at the maximum participation level and with no shifting is $1.7 million. The utilities estimate that the no-shifting, structural benefit to participants of joining the CPP program would be $1.9 million with total CPP participation of 930 MW. [16] The corollary of this would be a $1.9 million loss for customers joining and not shifting. Ninety percent of $1.9 million is $1.7 million.

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[15] - In the long-term, incentives for demand side programs should be consistent with what Californians are prepared to pay for incremental supply.

[16] - See cost-effectiveness analysis.

II.D.(1).b. Option B: Automation Incentive Payment.

This option is modeled on the CEC's Demand Responsive Buildings Program[17] (indeed, former program participants may be a good target for recruiting CPP participants). With this incentive option, the customer would receive an equipment installation incentive payment of $150 per kilowatt of load reduction to be used for qualifying demand reduction equipment. With the assistance of an energy engineering consultant selected by the CEC, the customer would estimate how much demand he could reduce during critical peaks and determine what equipment he or she should install. Half the payment would be made at the beginning of the program. At the end of the summer and after installation of the equipment, the customer would receive the other half of the payment. A contractor selected by the CEC would verify the amount of load reduction.[18] Load reduction would be calculated as the difference between the customer's load during critical peak events and the customer's baseline load, with the methodology to be determined by the CEC.[19] The definition of qualifying equipment would be the same as that used by the CEC in its 2001-02 rebate program.

Participation in Option B would be limited to a total incentive amount of $7.5 million, corresponding to 50 MW of demand reduction. If the average CPP customer reduces peak by 15% as suggested by the joint utilities, then this level would mean allowing participation in this incentive option by a total peak demand before shifting of 333 MW. This is about one-third of the potential participation estimate of 930 MW made by the joint utilities.

To implement the engineering consulting, a budget of $500,000 is proposed, with administration to be performed by the CEC. This is consistent with the consulting budget of $600,000 authorized by the CEC for the 2001-02 program.[20]

CUSTOMER PARTICIPATION IN MULTIPLE PROGRAMS/TARIFFS

Working Group 1 principals have recommended that additional incentives be considered to increase cost-effective participation in the programs. One way to accomplish this is to allow customers to participate on multiple compatible programs/tariffs, as long as joint participation is still cheaper than the cost of a

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[17] See "Innovative Peak Load Reduction Program," California Energy Commission, April 30, 2002, at http://www.energy.ca.gov/peakload/documents/2002-04-19_INNOVATIVEREVISE.PDF

[18] - See "Peak Load Reduction Program Measurement, Verification, and Evaluation Requirements," California Energy Commission, June 1, 2002, at http://www.energy.ca.gov/peakload/documents/overall_requirements.html

[19] - See "Protocol Development for Demand Response Calculation," prepared by Xenergy, Inc. for the CEC, August 1, 2002 for information. The study is available at http://www.energy.ca.gov/demandresponse/documents/index.html

[20] - Personal communication with Mike Messenger, CEC, January 14, 2002.

new peaker. Compatible programs could include ones that in combination provide:

- a reservation payment,
- an energy performance payment,
- a higher level of reliability.

This multiple program participation approach also gives utility system operators and procurers greater confidence in their scheduling/ procurement if they have an advance commitment on the amount of load reduction -- which DR programs with reservation payments bring.

The most common application of two-part real-time pricing allows both firm service and varying types of interruptible service to see a comparable hourly energy price signal. Similarly, we see that a customer could receive a reservation payment for an advance commitment to reduce demand in addition to receiving an energy or performance payment.   California has also allowed for customers to receive higher levels of reliability for a willingness to provide demand reduction. As noted in examples below, customers have been allowed to participate simultaneously on such programs and certain other DR programs.

When customers are participating in multiple programs, some priority or attribution may be necessary for determining how payments or program benefits are determined. For example, the PG&E E-DBP tariff currently states, “Load can only be committed to one program for any given hour of a curtailment, and customers will be paid for performance under only one program for a given load reduction. In other words, should the CAISO activate another interruptible program, an OBMC event or a rotating outage, while an E-DBP Event is in progress, those events will supersede an E-DBP Event, and no E-DBP payments will be applied for those overlapping hours.” In this case, the load reduction is attributed to programs other than E-DBP and hence no E-DBP energy payment is made.

The general principle of customer participation in multiple compatible programs or tariffs is illustrated with several examples.

Example 1.   A customer on interruptible rates could also participate on a two part Real-Time Pricing rate.

Example 2. A customer on an interruptible rate with a firm service level can also participate on the Optional Binding Mandatory Curtailment (OBMC) rate for higher reliability.   (already in place)

Example 3. A customer on OBMC rate or on an interruptible rate could also participate and receive payment, except during curtailment hours of OBMC or the interruptible rate, on a utility Demand Bidding program. (already in place)

Example 4. A bundled service customer on Critical Peak Pricing or Real-Time Pricing could also participate on the CPA Demand Reserve Partnership (or utility Demand Bidding programs), but would not receive energy payments from CPA (or the utilities) during hours when Critical Peak Prices are in effect.

Example 5. A customer on an OBMC rate can also participate in the CPA DRP, but would not receive energy payments from CPA during hours when an OBMC curtailment is in effect.

Example 6. A customer on interruptible rates could place additional load, below its firm service level on the interruptible rate, on the CPA DRP and receive reservation payments.

Example 7. A customer on existing interruptible rates could have existing curtailable load participate in the CPA DRP spot market options (either CAISO Supplemental Energy market or Day Ahead/Hour Ahead ancillary service markets), except that no payments shall be made during hours of curtailment due to the interruptible rate.

In the examples involving the CPA DRP, the utility programs take priority in payment. Therefore, the CPA would insure no payment was made during hours that the utility program curtailment events were being exercised. There may be other issues in resolving priorities and payments from multiple participation in programs.

WITHDRAWAL OF OBSOLETE TARIFF

As PG&E noted in section V.C.(11) of the November 15 report, there are no remaining customers enrolled under its existing experimental real-time pricing tariff, Schedule A-RTP, and would view the new CPP tariff as a reasonable successor to that tariff. Therefore, and as a clean-up matter, PG&E requests that the final Phase 1 decision in this rulemaking authorize cancellation of PG&E's pre-existing Schedule A-RTP.

III. MODIFICATIONS TO IMPLEMENTATION ACTIVITIES

As a result of the tariff and program modifications described in the previous section, the marketing and customer education activities described in the December 13 WG2 Report have been modified as delineated below.

III.A. Marketing and Customer Education

PG&E'S JOINT UTILITIES CPP PROPOSAL AND JOINT UTILITIES DEMAND BIDDING PROPOSAL

III.A.(1).a. Specific Marketing and Customer Education

PG&E's specific marketing, customer education, monitoring and evaluation plans as provided in the Second Report of Working Group 2 on Dynamic Tariff and Program Proposals: Implementation Issues issued on December 13, 2002, have no implementation changes. The only change is in reference to PG&E's RTP/CPP Proposal. This proposal has been modified and replaced with the (Joint Utilities) Critical Peak Pricing (CPP) proposal.

III.A.(1).b. Range of Customer Participation

PG&E's Joint Utilities CPP Proposal would be offered and available to all of PG&E's bundled customers with at least 200 kW of maximum demand that are currently served on PG&E's electric rate Schedules A-10, E19, and E-20.

The Joint Utilities recommend that this program be implemented on a voluntary basis, and believes, at this point, that 930 MW (PG&E – 430 MW, SDG&E 70 MW, and SCE – 430 MW) of enrolled load (representing a respective participation rate of 15% for each utility) is a conservative upper bound on the number of customers and amount of load that could be successfully recruited to participate in this program. These numbers translate to between 940 and 1310 customers at SCE and PG&E, and between 200 and 280 customers at SDG&E.

PG&E estimates that the participation level for the proposed Joint Utilities Demand Bidding Proposal would include the 40 PG&E accounts already participating in the current Demand Bidding Program and there would be an additional 60 PG&E accounts for a total of 100 accounts. The existing 40 accounts represent a minimum bidding demand of 6 MW and a maximum bid of 55 MW. When the participation rate increases to a total of 100 accounts, this will represent an additional minimum bidding demand of 9 MW (15 MW total) and an additional maximum bid of 82 MW (137 MW total).

SCE-SPECIFIC CUSTOMER MARKETING FOR STATEWIDE CPP PROPOSAL

III.A.(2).a. Customer Education/Recruitment

SCE's plans for customer education and recruitment of the medium to large power Critical Peak Pricing (CPP) rate option include using two different customer education and recruitment approaches, which vary by customer size. For those customers registering 500kW and greater, customer education and recruitment would be accomplished primarily through its Major Customer Account

Management Team. For those customers registering between 200kW and 499 kWh, SCE will employ a multifaceted approach of various media and delivery channels. Specifically, customer education and recruitment of this rate option would involve the following initiatives:

(1) Customers Registering 500 kW and Greater

Training

- Development and delivery of comprehensive internal and external large power CPP rate option training sessions and materials. Training and materials would be designed to provide SCE's Major Customer Account Managers/Executives and customers with program details, including an overview of the program, customer eligibility requirements, an explanation of how the program works, an estimate of customer benefits, customer enrollment requirements, an explanation of what the Major Customer Account Manager/Executive must do to enroll the customer into the program, what the customer must do to enroll in the program, an overview of bill presentation, and internal and external contacts for assistance with the program.
- Training would first be conducted with the Major Customer Account Managers/Executives to ensure their understanding of the program before marketing the program to customers. Customer training would follow Account Manager/Executive training.
- Training materials would include standardized internal and external presentations, program fact sheets/Q&A's, and a customer recruitment letter template.
- Assessment of internal and customer training would be conducted following each training session to determine overall effectiveness of training program.

Recruitment

- Recruitment would involve the development of a list of selected potential large power CPP customers
- The list would be given to the appropriate Major Customer Account Managers/Executives for one-on-one contact with potential large power CPP customers.
- Major Customer Account Managers/Executives would use various external materials, such as rate/program fact sheets and Commonly Asked Questions and Answers, to assist customers in understanding the program and to solicit their participation in the program.
- Annual Performance Plans for Account Managers/Executives could include incentives for enrolling customers in large power CPP.
- Account Managers/Executives would incorporate information on the large power CPP program in presentations to customer groups that focus on California Electricity Marketplace issues. These presentations occur throughout the year, but are conducted primarily pre-summer and throughout the summer.

- Major Customer Account Manager/Executive Communications would incorporate information on the large power CPP program in its major customer bulletin/newsletter.
- Large Power CPP program information would be placed on SCE's website under Load Reduction Incentives.

On-Going Program Communications

- Customer communications would continue throughout the entire large power CPP program through the development and delivery of various program communications letters and on-going one-on-one Account Manager/Executive customer contact.

(2) <u>Customers Registering Between 200kW and 499kW</u>

Training

- Development and delivery of comprehensive internal medium power CPP rate option training and materials. Training and materials would be designed to provide SCE's Major Customer Account Managers/Executives and Unassigned Customer Account Managers with program details, including an overview of the program, customer eligibility requirements, an explanation of how the program works, an estimate of customer benefits, customer enrollment requirements, an explanation of what the Major Customer Account Manager/Executive and Unassigned Customer Account Manager must do to enroll the customer into the program, what the customer must do to enroll in the program, an overview of bill presentation, and internal and external contacts for assistance with the program.
- Training would be conducted with Major Customer Account Managers/Executives and Unassigned Customer Account Managers to ensure they're understanding of the program before marketing the program to their customers, such as associations and trade groups.
- Training materials would include standardized internal and external presentations, program fact sheets, Q&A's, and a customer recruitment letter template.
- Assessment of internal and customer training would be conducted following each training session to determine overall effectiveness of training program.

Recruitment

- Recruitment would involve the development of a list of selected potential medium power CPP customers and would be utilized in targeted media efforts, such as direct mail and newsletter articles which would be sent to potential participants who meet characteristic criteria and would be most likely to enroll and benefit from the pilot.
- The list would be given to the appropriate Major Customer Account Managers/Executives for one-on-one contact with potential medium power CPP customers.

- Major Customer Account Managers/Executives would use various external materials, such as rate/program fact sheets and Commonly Asked Questions and Answers, to assist customer in understanding program and solicit their participation in the program.
- Annual Performance Plans for Account Managers/Executives and Unassigned Customer Account Managers could include incentives to enroll customers in the medium power CPP.
- Unlike recruitment efforts for customers greater than 500kW, joint efforts with associations and trade groups (i.e., BOMA, CMA, etc.) to reach high potential unassigned, medium-sized business customers, supported by sales support materials to support outreach events such as flyers, rate/program fact sheets, Commonly Asked Questions and Answers, and placement ads would be utilized.
- Medium power CPP program information would be placed on SCE's website under Load Reduction Incentives.

On-Going Program Communications

- Customer communications would continue throughout the entire medium power CPP program through the development and delivery of various program communications letters and on-going one-on-one Major Customer Account Manager/Executive customer contact and Unassigned Customer Account Manager contact with associations and trade groups.

TABLE 1: SCE's Proposed Customer Education and Recruitment Schedule

	Implementation Timeline*									
Program	**03/03**	**4/03**	**5/03**	**6/03**	**7/03**	**8/03**	**9/03**	**10/03**	**11/03**	**12/03**
Critical Peak Pricing										
Rep Training Sessions										
Customer Training Sessions										
Customer Recruitment Mailings/Direct Customer Contact										
Customer Program Management Letters										
*Assume final CPUC approval date = 2/28/03										

SDG&E CUSTOMER MARKETING FOR JOINT UTILITIES CPP PROPOSAL

The joint utilities CPP proposal has been designed to be more attractive for customers with large air conditioning loads, including commercial office buildings. SDG&E's service territory tends to have a large amount of industrial parks in which office space within the industrial park may be separately metered. Individually, these meters may have loads below 200kW, but in aggregate, the loads could easily exceed the 200kW threshold. For this primary reason, SDG&E is proposing to make available the CPP option to all AL-TOU/EECC customers. The CPP would then be open to AL-TOU/EECC commercial customers with demands greater than 20kW.

By making the CPP option available to all AL-TOU/EECC customers, SDG&E expects a higher level of participation than if the option were to only be made available to the greater than 200kW customers. In doing so, SDG&E recognizes that additional resources will be required to identify, target, educate and promote CPP.

SDG&E expects to the timeline for CPP implementation to be the same as described for HPO in the WG2 - December 13, 2002 report.   In addition, similar customer education and marketing activities will be incorporated into the CPP plan. SDG&E will augment these activities with the following in an effort to achieve a significant level of CPP participation.

Initially, SDG&E will conduct market research to determine the most likely candidates for CPP. After segmenting customers by industry type, SDG&E will perform rate analyses by industry type from a sampling of the >300kW customers. The rate analyses will help determine which industry types are more likely to benefit from participating in CPP. SDG&E will extrapolate these results for targeting customers with demands under 200kW.

Utilizing the information gathered from market research and by employing existing account representatives, SDG&E will promote CPP to the larger customers (>200kW). As a result of our strong customer relationships, larger customers are more familiar with utility demand response programs and subsequently, may be more likely to understand CPP and its potential benefits. Although SDG&E expects to obtain a higher level of participation from the larger customers, significant effort will be directed toward the small to medium-size customers.

Generally, customers with demands below 200kW may not be familiar with utility demand response programs. This is due to the fact that existing reliability-type demand response programs require a minimum load reduction of 100kW, which all but excludes the small to medium-size customers from participating. Because CPP does not require a minimum load reduction, all AL-TOU customers are eligible to participate. In order to achieve any level of customer participation for the under 200kW class of customers, extensive customer education must be carried out. SDG&E recognizes that this activity will take a considerable amount of resources and time.

SDG&E will utilize several internal resources to target the small to medium-size commercial customers. These resources include existing Demand Response program managers, special investigators who respond to business customer inquiries, and mass markets personnel. SDG&E's mass markets team has contact information for over 150 business groups in its service territory and has established relationships with several trade associations including: American

Electronics Association, BIOCOM, Building Industry Association, Building Owners & Managers Association (BOMA), various Chambers of Commerce, California Manufacturers Association, California Restaurant Association and the San Diego County Hotel-Motel Association. SDG&E will partner with these and other associations to inform their members of the various applicable demand response programs and tariffs including HPO and CPP.
In addition to attending business group meetings, SDG&E will seek out and actively participate in appropriate trade shows and conferences. SDG&E will coordinate these activities with its energy efficiency team to leverage its resources and ensure message continuity.

Customer education and recruitment will not stop at attending trade association meetings or simply informing members of demand response opportunities. SDG&E will strive to achieve customer participation by working one-on-one with interested customers. Customers will want to understand how CPP impacts them specifically. From past experience, SDG&E understands that several meetings with specific company representatives may be necessary to attain customer participation.

Similar to the HPO proposal, SDG&E representatives will meet with customers to provide them with a customer-specific information package. The package will include general information about CPP (and other demand response programs) and either meter-specific rate analyses (for accounts with IDR meters) or industry-type rate analyses (for accounts without IDR meters) illustrating the potential cost impacts of selecting the CPP option. SDG&E representatives will also conduct "what-if" scenarios for customer-specific accounts to help illustrate how shifting or reducing load during critical peak periods can achieve additional cost savings.

There are about 15,000 AL-TOU/EECC accounts with demands over 20kW in the SDG&E service territory. These accounts represent about 1900MW of peak demand. SDG&E will strive to enroll 70MW or about 4% of AL-TOU/EECC total peak demand in CPP.

CPA DEMAND RESERVES PARTNERSHIP

III.A.(4).a. General Description

The Demand Reserves Partnership pays large end users (both bundled service and direct access) for being available to reduce load when needed to function as the equivalent of a Call Option on peaking capacity or Ancillary Services in the wholesale market.

Because the core DRP provides customers a modest reservation payment and a modest energy payment, it is an intermediate option between interruptible rates (large reservation payment and no energy payment) and utility Demand Bidding proposals (no reservation payment and large energy payment).

CPA will calculate the baselines and distribute the dollars earned[21] for not only its core program, but also the additional options – ISO credit and transmission pilot – as a result of a procurement contract with the DWR and/or utilities. The necessary UDC support of such programs will largely be limited to coordination of customer education and marketing, minor assistance in efficiently obtaining 15 minute data from the CEC meters, and scheduling coordination services of the Demand Reduction with the ISO. No major back-office support or system changes by the UDCs are envisioned, beyond that necessary for handling of Ancillary Service end users in the ISO market, as described in the Nov 15 report. CPA's budget for this program includes $2 million of support from the utilities, plus $2.5 million for the major software development. As an incentive to attract more end users, CPA also proposes that about $6 million of CEC meters be added at customer sites where the customers site demand exceeds 200 kW[22], but the customers do not yet have a CEC meter. All these costs have been reflected in the cost-effectiveness tests.

III.A.(4).b. Customer Education and Marketing Plan

CPA believes that utilities should receive credit toward any DR goals for any load on the DRP. Therefore, CPA believes that it should provide information to the utilities so that the DRP can be marketed by the utilities as a customer option along with other DR options. In addition, CPA will have Demand Reserve Providers marketing and educating the customers on the DRP. Further, CPA believes that the Providers should receive a fee for any customers whose leads they generate that yield customers signing up for the utility DR programs.

The Demand Reserve Providers continue to promote the DRP, particularly in encouraging customers to participate by next summer. CPA has had the following associations encourage their members to considering participating in the DRP: Association of California Water Agencies, Building Owners and Managers Association, Silicon Valley Manufacturers Group, California Manufacturing and Technology Association, League of California Cities, California State Association of Counties, California Business Properties Association, Orange County Business Council, California Oil Producers Electric Cooperative, and Golden State Cooperative. CPA will continue to work with

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21 Currently the dollars earned by end users pass from CPA through the Demand Reserve Provider to the end user.

22 CPA envisions two major categories of such customers. First, there are a significant number of PG&E Pumping customers whose demand exceeds 200 kW. Second, there are a number of sites (e.g., shopping malls) where one meter at the site exceeds 200 kW, but other meters at that site have demand below 200 kW, but are worth controlling since the total site significantly exceeds 200 kW. We understand that SDG&E separately is endeavoring to install CEC interval meters on all sites between 200 and 300 kW that were not included in the first wave of installation.

these associations to not only promote the DRP, but the other Demand Responsive options as appropriate for their members.

In furthering this Partnering approach, CPA proposes to enter into an alliance with The Energy Coalition, the nonprofit developer and implementer of The Regional Energy Efficiency Initiative (REEI). The REEI is demonstrating the effectiveness of a bottom up, energy efficiency delivery process for cities and their communities. The Energy Coalition has a long history of developing and implementing demand responsive Energy Cooperatives. Working in concert with SCE, The Energy Coalition developed the REEI Demonstration Project. The success of this endeavor caused the CPUC to select The Energy Coalition to expand the REEI into the Six Cities Project as part of the Commission's third party initiative. The REEI program is an effective process for partnering through cities and communities with end users and their governmental representatives to deliver energy efficiency, which includes demand responsiveness in six southern California cities. CPA believes that an alliance with the Energy Coalition gives CPA a ready opportunity to not only test an alternate marketing and customer education approach for DR in the six cities, but an enhancement in its partnering process in other communities.

Similarly, in supporting the transmission pilot, CPA expects to work closely with the City and County of San Francisco and other key groups to achieve targeted implementation.

III.A.(4).c. Range of Customer Participation

CPA has had three types of customers express interest in this program:

- Pumping customers, both oil and water.
- Industrial, who want more flexibility than they can obtain on an interruptible rate,
- Commercial, both office building and retail space.

CPA is targeting customers who have over 200 kW at one site. Some sites have multiple meters, including meters less than 200 kW.

To date CPA has received 500 MW of bona fide interest to participate in the DRP. Depending on how quickly that cost recovery issues are resolved, CPA would expect about a quarter to a half (or 125-250 MW) of this potential to be available this summer.

III.A.(4).d. Monitoring and Evaluation

As part of its settlement function with DWR and/or the IOUs, CPA will be monthly preparing reports on the number of MWs nominated, dispatched and delivered on the program.

III.B. Proposed Cost Recovery Mechanism

This section is essentially the same as described in WG2's second report, dated December 13, 2002, and therefore a large amount of text is repetitive.

Section 6 of WG3's Report, dated December 10, 2002, and Section V.B. of WG2's second report, dated December 13, 2002, details the UDCs joint cost recovery proposal. WG2 agrees to apply a similar methodology of cost recovery for WG2 demand response programs and pilots as proposed by the UDCs to provide funding for reasonable expenditures on authorized WG3 experimental statewide pilot programs. WG2 recommends adoption of the proposed Advanced Metering and Demand Response Account (AMDRA) as the method of documenting costs associated with WG2 demand response programs and pilots as described in the sections below. WG2 recommends the Commission also provide funding for the reasonable expenditures of Third Party Vendors (VENDORS)[23] authorized to participate in approved WG2 demand response programs and pilots to the extent the Commission adopts such programs and pilots.

WG2 consents to the proposed cost recovery mechanisms detail below, and a total 2003 budget cap of $20.9 million, which includes funding for both authorized WG2 demand response programs and pilots.[24] Incentive payments and energy bill changes[25] are part of procurement and therefore not subject to the budget cap. This budget cap does not include funding for programs proposed for WG3. Table 2 below details the 2003 estimated WG2 demand response program and pilot expenditures[26].

The IMServ Critical Peak T&D pilot proposal could apply to customers above and below 200 kW, cost about $3,650,000, of which $2,000,000 is expected to apply to customers below 200 kW, $1,150,000 would apply to customers above 200 kW, and $500,000 is to apply to incremental metering systems costs.[27]

WG2 agrees that future budget cap changes could be proposed through annual advice letter filings at the Commission's Energy Division. WG2 recommends the Commission allocate the AMDRA total 2003 budget cap between the UDCs according to which programs are authorized and which UDC implements that program (because those costs vary by program, WG2suggests that proposed

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[23] Infotility, ACWA, and IMServ.

[24] See Table 2.

[25] See Table 3.

[26] Some estimated expenditures could include some 2002 costs.

[27] Of the IMServ Program Administration budget, $150,000 is to cover utility costs, and the rest is to cover CPA or customer costs.

allocations be included in the draft Phase I decision and that the Parties be allowed to comment on the allocations, based on estimated program costs for the programs adopted in the draft decision). WG2 recommends that all activity associated with WG2 demand response programs and pilots be reported to the Commission monthly.

The costs included in Table 2 include monitoring and evaluation plans, marketing and customer education plans, customer notification systems for pricing and critical peak events, metering and meter data collection for customers who do not have meters under the ABx1 29 funded real-time metering program[28], Billing system modifications, and other operations and maintenance and administration costs as necessary.

Details of program activities and costs were provided in Sections II.C, III, and V of WG2's second report, dated December 13, 2002. Additional details were provided in Section V of WG2's first report, dated November 15, 2002. Sections of that report provide details on the implementation of each of the proposals and subsection (5) for each of the proposals specifically describes Sources and Levels of Costs.

As recommended in WG2's second report, WG2 recommends that the Phase I decision in this proceeding, include authorization for VENDORS to recover reasonable costs of participation in authorized WG2 demand response programs and pilots. Funding for VENDORS could be through UDCs AMDRA, the CEC's PIER[29], or the CPUC's Public Goods Charge. The PIER and Public Goods Charge are already in place and are consistent with the basic intent of that charge.

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[28] Most customers above 200 kW have such meters, but some do not.
[29] For funding purposes, some portions of WG2 demand response programs and pilots could be considered research programs.

TABLE 2: 2003 Estimated Expenditures on WG2[30] Demand Response Programs and Pilots[31]

Proposer	Program Name	Program Administration Costs (O&M + A&G) for Calendar Year 2003	Capital Costs for Calendar Year 2003	Total
ACWA	CPP	$400,000	$600,000	$1,000,000
CPA	CallOp	$1,700,000	$2,000,000	$3,700,000
CPA	NonSpAS	$1,000,000	$3,500,000	$4,500,000
CPA	SupEn	$1,000,000	$1,500,000	$2,500,000
CPA	ISO Credit	$1,000,000	$1,000,000	$2,000,000
Infotility	TPRTP	$155,000	$145,000	$300,000
IMServ	CPT&D	$1,150,000	$500,000	$1,650,000
Joint UDC's	CPP	$3,800,000	$400,000	$4,200,000
PG&E	DBP	$110,000	$164,000	$274,000
SCE	DBP	$514,000	$0	$514,000
SDG&E	DBP	$8,000	$7,000	$15,000
SDG&E	HPO	$50,000	$240,000	$290,000
TOTAL (proposed cap)		$10,887,000	$10,056,000	**$20,943,000**

30 The Program Administration Costs in the table below for the CPA options are half to cover utility incremental costs and half to cover CPA incremental costs, except that $500,000 is earmarked for enhanced marketing efforts through The Energy Coalition. The Capital Costs for the CPA program, except for $2,500,000 in incremental software development for better handling of meter data to support Demand Response consistent with ISO practices, provide $5,500,000 more for CEC meters. CPA recommends the allocation of these costs to be for PG&E, Edison, SDG&E, respectively: Program Administration (45%, 45%, 10%), Capital Costs (53%, 14%, 32%). PG&E is provided a higher capital percent because most of its Pumping customers do not have CEC meters.

31 The $2.5M cost estimate reflects the need for PG&E to develop and implement CPP billing capability and to undertake an aggressive marketing effort to 8,000 of PG&E's largest customers (>200kW). Some of these costs have been included in PG&E's 2003 GRC, if the Commission approves recovery of these costs in the GRC, PG&E will modify its recovery proposal in this proceeding to ensure costs are not recovered twice. This estimate excludes approximately $1.12 million in funds requested in the GRC associated primarily with public carrier air time charges for retrieving interval data from the ABx1-29 meters.

METHODS OF COST RECOVERY

WG2 recommends the UDCs be allowed to: (1) establish regulatory accounts to record incremental one-time and on-going demand response program and pilot costs not currently covered in rates, (2) utilize established balancing accounts to recover under collected revenues, (3) utilize established balancing accounts to recover customer incentive payments, and (4) provide for VENDORS to recover reasonable expenditures to participate in authorized WG2 demand response programs and pilots.

WG2 recommends the following cost recovery treatment for all UDC and Vendor reasonable costs to assess, acquire, deploy, install, operate and maintain advanced meter technologies. Also, all reasonable costs related to communication hardware, billing systems, and measurement data collection software enhancements. UDCs and VENDORS should also be allowed to recover all incremental costs to design, implement, and market authorized WG2 demand response programs and pilots.

O&M AND A&G COSTS TO IMPLEMENT LARGE CUSTOMER TARIFFS INCURRED PRIOR TO THE PHASE I DECISION

WG2 recommends the Commission provide authorization in its Phase I decision for the UDCs and VENDORS to include and recover reasonable costs associated with various activities necessary to implement authorized WG2 demand response programs and pilots for large customers by June 2003. WG2 recommends the Commission authorize the UDCs to create a regulatory account to record one-time and on-going incremental operations and maintenance (O&M) and administrative and general (A&G) costs associated with work prior to a Phase I decision. Details of the proposed AMDRA were described in WG2's second report, dated December 13, 2002. As mentioned in that report, prior to the Phase I decision, the AMDRA would be capped at $1 million for both Working Group 2 and 3. Each year's recorded WG2 demand response program and pilot costs would be recovered in the subsequent year via an annual advice letter filing at the Commission.[32]

O&M AND A&G COSTS TO IMPLEMENT LARGE CUSTOMER TARIFFS INCURRED SUBSEQUENT TO THE PHASE I DECISION

One-time and on-going incremental O&M and A&G cost estimates will probably change after the Phase I decision, and certainly over the next five years. WG2 proposes that the Phase I decision order a methodology to change the total budget cap in the AMDRA. WG2 recommends using annual advice letter filings for the AMDRA as the place for the UDCs to propose changes in the AMDRA

[32] Alternatively PG&E or SCE could seek cost recovery in the Revenue Adjustment Proceeding (RAP), although the timing and frequency of future RAPs are uncertain. If the Commission discontinues use of the RAP as a summary rate and revenue adjustment, SCE and PG&E propose to apply interest to these amounts and to recover them in the next rate case.

budget caps. For separate tracking purposes, WG2 demand response program and pilot costs prior to the Phase I decision could be recorded in a sub account of the AMDRA.

CAPITAL

WG2 recommends that all reasonable capital additions incurred in WG2 demand response programs and pilots should be treated as authorized additions to the respective UDCs plant and associated annual depreciation expense as authorized by the Commission for each UDC. Authorized capital expenditures could be on a per customer basis for certain specific variable plant additions, e.g., advanced meters, or on a total estimated basis, e.g., billing system addition or measurement data collection software.[33]

INCENTIVE PAYMENTS

WG2 recommends that for Commission authorized WG2 demand response programs and pilots requiring an incentive payment, those payments would be recorded in the appropriate regulatory account.[34]

REVENUE SHORTFALLS

There is a consensus in WG2 to allow the recovery of UDC revenue shortfalls due to load shifting, load reduction, or bill credits from WG2 demand response programs and pilots offered to bundled service customers from all bundled customers through each UDC's existing balancing accounts.[35] With the existing

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[33] SDG&E would use its existing "Adjustment to Electric Distribution and Gas Margin Rates" mechanism. Each year's recorded capital cost and associated depreciation cost will be recovered in the subsequent year via an annual advice letter filing in October each year and subsequent rate changes effective January 1 of the following year.

[34] For SDG&E, these payments would be recorded directly in SDG&E's Energy Resource Recovery Account (ERRA) balancing account authorized in D.02-10-062. The ERRA describes the process to recover over/under collections. If the Commission authorized programs involve utility "capacity" incentive payments, then these payments will be estimated by the utility and recovered through ERRA. The actual "capacity" incentive payments will be recorded in the ERRA balancing account and reconciled with the actual revenue collected and recorded and adjusted in the subsequent year's revenue requirements

[35] For PG&E, the current Emergency Procurement Surcharge Balancing Account (ESPBA) and the Transition Revenue Accounting (TRA) mechanisms record procurement costs including retained generation costs. Additionally, the current TRA mechanism ensures that full collection of PG&E's authorized distribution, nuclear decommissioning, and public purpose program revenue requirements will continue even if changes in usage patterns from demand response programs produce revenue under-collections of the type described here. PG&E will seek similar accounting mechanisms once the TRA is no longer in place.

For SDG&E, a material change in T&D under collections will trigger SDG&E to file an advice letter to create a T&D regulatory account to track under collections resulting from R.02-06-001 demand responsiveness programs. Currently, SDG&E does not have a mechanism for distribution revenue under collections from authorized levels.

balancing accounts, the UDCs believe it is unnecessary and, in fact, burdensome, to formally track costs and revenue shortfalls by tariff option/program, i.e., assuming the same level of sales, revenues received under the new tariff compared to revenues that would have be received under the otherwise applicable tariff.

Table 3 shows the 2003 estimates[36] of the incentive payments and revenue shortfalls associated with WG2 demand response programs and pilots as used in the cost-effectiveness analysis.[37] These estimates depend on the number of participants, amount of demand reduction, and several other factors and, therefore should be treated as rough approximations.

TABLE 3: 2003 Estimated Incentive Payments and Bill Changes For WG2 Demand Response Programs and Pilots[38]

Proposer	Program Name	Estimated Incentive Payments	Estimated Energy Bill Changes	Total
ACWA	CPP	$5,150,000	$3,855,000	$9,005,000
CPA	CallOp	$10,800,000	$3,600,000	$14,400,000
CPA	NonSpAS	$6,700,000	$1,800,000	$8,500,000
CPA	SupEn	$8,000,000	$270,000	$8,270,000
CPA	ISO Credit	$1,000,000	-$3,000,000	-$2,000,000
Infotility	TPRTP	$2,500,000	$0	$2,500,000
IMServ	CP T&D	$2,625,000	$450,000	$3,075,000
Joint UDC's	CPP	$0	$8,835,000	$8,835,000
PG&E	DBP	$173,000	$0	$173,000
SCE	DBP	$378,000	$0	$378,000
SDG&E	DBP	$8,000	$3,000	$11,000
SDG&E	HPO	$0	$426,000	$426,000
TOTAL		$37,334,000	$16,239,000	**$53,573,000**

For SCE, these payments would be recorded in the Procurement Related Obligations Account (PROACT). This mechanism assures full collection of SCE's authorized distribution, nuclear decommissioning, and public purpose program revenue requirements will continue even if changes in usage patterns from demand response programs produce revenue under collections of the type described here. SCE will seek similar accounting mechanisms once the PROACT is no longer in place.

[36] Some estimates could include some 2002 expenditures.

[37] The IMServ proposal was not included in the cost-effectiveness analysis as the data was not available.

[38] The "Incentive" payments on the CPA program and IMServe program are actually commodity procurements from DWR or from the IOUs. At least some procurements (e.g., ISO credit, transmission) will need to come from the IOU procurement rather than DWR procurement. The Bill Change for the CPA ISO Credit program is negative because it leads to a net increase in the customer's bill (versus a net decrease by the other programs).

COST INCURRED PRIOR TO COMMISSION DECISION AUTHORIZING EXPENDITURES FOR R.02-06-001

As discussed above, WG2 recommends the Commission authorize the UDCs to record WG2 demand response program and pilot costs incurred prior to the Commission's Phase I decision in a sub account of the AMDR Account. The costs that would be recorded should be expanded to include all reasonable advance lead-time activities needed to continue to develop the WG2 tariffs and programs and the WG3 statewide pilot before the Commission issues its decision in Phase I. These costs would be capped at $1 million for all three UDCs combined ($450,000 for PG&E and SCE respectively, and $100,000 for SDG&E). In other words, in addition to the prerequisite market research needed for both Working Group 2 and 3 demand response programs and pilots, the UDCs would also seek to record the costs of various activities that of necessity are going to need to be continued over the next three months. These include: development of information, technology, and rate treatments; sample design; and any other activity needed to continue to refine and implement the pilot and tariffs to ensure that they have a reasonable chance of being in place by the summer of 2003. The UDCs anticipate that in its Phase I decision, the Commission will authorize expansion of the proposed balancing account to include further implementation costs.

LANGUAGE REQUIRED IN COMMISSION RULING AUTHORIZING ESTABLISHMENT OF THE AMDRA

WG2 recommends the following language (implementing the above concept) be included in a Commission Ruling authorizing the UDCs to establish these accounts. This level of detail is necessary for the UDCs to be in a position to quickly file uniform, complying advice letters:

> "The utilities shall each file advice letters establishing Advanced Metering and Demand Response Balancing Accounts (AMDRAs). The purpose of the AMDRAs is to record and recover the incremental, one-time set-up and on-going Operating and Maintenance (O&M) and Administrative and General (A&G) expenses incurred to implement, or in reasonable anticipation of implementing, the demand response programs adopted by the Commission in R. 02-06-001. These costs would be limited to a total of $1 million for the three utilities combined ($450,000 for PG&E; $450,000 for SCE; and $100,000 for SDG&E) of costs incurred until the Commission issues its Phase I decision in this proceeding and approves an accounting mechanism for additional expenditures necessary to implement its decision. The AMDRAs will apply to all customer classes, unless the Commission specifically excludes any class. The revision dates applicable to the AMDRAs shall be as determined in each utility's annual advice letter filing or as otherwise ordered by the Commission. The AMDRAs will not have a rate component. The utilities shall maintain their respective AMDRAs by making entries at the end of each month as follows:

A debit entry equal to the utility's incremental one-time "set-up" and on-going O&M and A&G expenses for advance lead-time work necessary in anticipation of implementing WG2 demand response programs and pilots.

A credit entry equal to the interest on the average of the balance at the beginning of the month and the balance after the above entry at a rate equal to one-twelfth the interest rate on three-month Commercial Paper for the previous month, as reported in the Federal Reserve Statistical Release, H.15 or its successor."

PROCESS TO ESTABLISH THE ACCOUNTS

WG2 and the UDCs propose that the following steps be followed to establish the AMDRA:

- Ruling issued directing the UDCs to each file advice letters within five business days (assumes that the ruling contains language as comprehensive and detailed as that specified above)
- Parties have 10 days to comment on advice letters
- Advice letters become effective retroactive to the date of filing upon written approval of the Energy Division (does not contemplate resolution or CPUC decision).

METHODS OF VENDORS COST RECOVERY

VENDORS are not regulated by the Commission, and therefore require a somewhat different cost recovery mechanism than the UDCs joint cost recovery proposal. Funding for VENDORS reasonable expenditures on authorized WG2 demand response programs and pilots could be through contracts with the UDCs, funding through the CEC's PIER, or through the CEC's Public Goods Charge. Since several options are available, the Parties are encouraged to address this issue more specifically in their December 30 comments to this report.

Also, reasonable VENDOR costs associated with various going forward activities need to be recovered, such as, development of information, technology, and rate treatments; sample design; and any other activity needed to continue to refine and implement WG2 demand response programs and pilots to ensure a reasonable chance of being in place by June of 2003.

WG2 recommends that any VENDOR funding for WG2 demand response programs and pilots include a contracting mechanism[39] with the UDCs through authorized balancing accounts.[40] WG2 believes that demand response

[39] Prime contractor or Subcontractor.

[40] AMDRAs.

programs and pilots could be categorized as energy efficiency programs and therefore, could be funded through the CEC's PIER. Similarly, the CEC's Public Goods Charge could be used to fund VENDOR cost recovery. The CPA's DWR mechanism for demand reserves and demand response is slightly different from the CEC's PIER because those programs are viewed as procurement just like the purchase of power from a combustion turbine, so the cost recovery for the CPA programs comes from the commodity accounts of the UDCs. WG2 agrees, that as long as the Commission continues to fund the DWR revenue requirement or demand response through utility commodity procurement, such a recovery mechanism is reasonable.

IV. COST EFFECTIVENESS ANALYSIS

This section is essentially the same as described in WG2's second report, dated December 13, 2002, and therefore a large amount of text is repetitive.

This rulemaking was initiated in order to address, comprehensively, policies designed to develop demand flexibility as a resource to enhance electric system reliability, reduce power purchase and individual consumer costs, and protect the environment. (OIR 02-06-001, mimeo, p.1) Working Group 2 was asked to develop a Plan for large customers to include "a complete benefit-cost analysis" (ALJ ruling, 9/5/02, p. 2). The ALJ (Ruling on 10/2/02, p. 7) later offered as an option: "The Standard Practice Manual (for DSM programs) methodology will be used as a tool since it allows an assessment of demand reductions from multiple viewpoints: society; customer; utility; ratepayer." The ALJ elaborated, "we do not wish to turn Phase 1 into a detailed data/modeling exercise … we are simply looking for a range of costs and benefits." (Ibid.) Later the ALJ provided a set of avoided cost assumptions that the Working Groups could use and added, "Though we expect cost-effectiveness analysis for all pilot programs and tariffs … at this point, the purpose of the cost-effectiveness analysis is simply informational and may also help us distinguish between various proposals." (ALJ Ruling, 11/13/02, p. 2)

Based on this direction, Working Group 2 applied the Standard Practice Manual to evaluate the cost-effectiveness of all programs. As discussed in the Issues sub-section at the end of this cost-effectiveness discussion, there are some concerns with using the Standard Practice Manual that we believe should be addressed beyond Phase 1.

In summary, this analysis shows that almost all options are cost-effective from the total resource cost perspective when compared against a new peaker (as specified in ALJ ruling 11/13/02). A number of options, however, are not cost-effective when compared against an existing peaker (as also specified in ALJ ruling 11/13/02). Some of the programs are not cost effective from a non-participating customer perspective as described in the analysis section which follows. But as some have observed and as discussed in the Issues section, if these DR options better reflect the costs of providing electricity, such a change may not be less equitable.

IV.A. Description of Framework

The October 2001 “California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects” (SPM) sets forth four groups of tests for evaluating Demand Side Management Programs. Each test group examines the program from a different perspective. The SPM describes those test groups and their perspectives as:

TOTAL RESOURCE COST TESTS

> "This test represents the combination of the effects of a program on both the customers participating and those not participating in a program. In a sense, it is the summation of the benefit and cost terms in the Participant and the Ratepayer Impact Measure tests, where the revenue (bill) change and the incentive terms intuitively cancel." ... "The benefits calculated in the Total Resource Cost Test are the avoided supply costs--the reduction in transmission, distribution, generation, and capacity costs valued at marginal cost--for the periods when there is a load reduction." ... "The costs in this test are the program costs paid by both the utility and the participants plus the increase in supply costs for the periods in which load is increased." (Pages 23-24).

RATEPAYER IMPACT MEASURE TESTS

> "The benefits calculated in the RIM test are the savings from avoided supply costs. These avoided costs include the reduction in transmission, distribution, generation, and capacity costs for periods when load has been reduced and the increase in revenues for any periods in which load has been increased." ... "The costs for this test are the program costs incurred by the utility, and/or other entities incurring costs and creating or administering the program, the incentives paid to the participant, decreased revenues for any periods in which load has been decreased and increased supply costs for any periods when load has been increased." (Page 17)

PARTICIPANT TESTS

> "The benefits of participation in a demand-side program include the reduction in the customer's utility bill(s), any incentive paid by the utility or other third parties, and any federal, state, or local tax credit received." ... " The costs to a customer of program participation are all out -of-pocket expenses incurred as a result of participating in a program, plus any increases in the customer's utility bill(s)." (Page 11).

PROGRAM ADMINISTRATOR TESTS

> “The benefits for the Program Administrator Cost Test are the avoided supply costs of energy and demand, the reduction in transmission, distribution, generation and capacity

valued at marginal costs for the periods when there is a load reduction." … "The costs for the Program Administrator Cost Test are the Program costs Incurred by the administrator, the incentives paid to the customers, and the increased supply costs for the periods in which load is increased."

ADJUSTMENTS TO THE SPM METHODOLOGY

The SPM proscribes methods for evaluating Demand Side Management programs. The programs under examination in this proceeding are in some ways more simple and in some ways different from those envisioned in the SPM. In building the evaluation tools used in this cost evaluation, certain adjustments were made to the SPM approach. These adjustments either simplified away unused detail or added capabilities not anticipated in the SPM yet required by this proceeding. The following bullets briefly describe these adjustments.

- Recognize Price Changes – SPM methodology recognizes only quantity changes and not price changes in assessing benefits and costs. However, this proceeding examines quantity changes induced by price changes. Model inputs included both price and quantity changes.

- Calculate Total Changes – SPM methodology uses differential analysis. For instance, the benefit to a participant to a demand reduction would be the demand reduction times the demand price. Extrapolating this differential approach to situations with both price and demand changes would ignore cross term components that might be large with successful demand responses. Hence inputs recognizing these cross components were required.

- Discard Unconsidered Benefit and Cost Components - The SPM includes components not considered at this stage of this proceeding. For instance, the SPM considers alternative fuels. The evaluation tools did not include unused SPM components such alternative fuels.

- Adjust to Continuum – The SPM essentially proscribes using absolute values. For instance, avoiding a cost would show up only as a benefit while increasing a cost would show up as a cost. The evaluation tools simplified the treatment of such a cost by treating a reduction as a benefit that changes sign if it becomes an increased cost.

- Limit to NVP and Benefit Cost Ratio Tests - Each test group in the SPM includes 3 to 5 tests with each including a test of Net Present Value of benefits less costs (NPV Tests) and a test of the ratio of discounted benefits to discounted costs (Benefit/Cost Ratio Tests). The evaluation performed by Working Group 2 only includes NPV Tests and Benefit/Cost Ratio Tests.

- Eliminate Program Administrator Test – In the requested ratemaking environment, where utilities would recover costs associated with demand reduction programs through balancing accounts or other mechanisms, there would be no program administrator costs which are not passed on to non-participating customers. Thus, there is no need for as separate Program Administrator Test.

COST EVALUATION EQUATIONS

Appendix C contains the detailed equations that used to evaluate to programs proposed in this proceeding. The details in the equations easily obscure understanding of what they do and how they relate. In order to gain greater insight it is useful to look at the equations after the present value discounting and summations have taken place. The net present value related equations become:

Total Resource Cost Test

$$NPVTRC = UAC - PRC - PCN$$

Ratepayer Impact Measure Test

$$NPVRIM = UAC - BC - PRC - INC$$

Participant Test

$$NPVP = BC + INC - PC$$

Where

- BC = Bill Changes
- INC = Incentives
- PC = Participant Costs
- PCN = Net Participant Costs
- PRC = Program Administrator Costs
- UAC = Utility Avoided Costs

The figure below shows the relationship between these various cost effectiveness measures. In this framework, the Total Resource Cost Test, the Ratepayer Impact Measure Test, and the Participant Test are consistently related to each other. In particular, the Total Resource Cost Test is essentially the sum of the Participant Test and the Ratepayer Impact Measure Test.

TABLE 4: Net Present Value Relationships – One Framework

All Ratepayers NPVTRC = UAC – PRC - PCN
Non-Participating Ratepayers NPVRIM = UAC – BC – PRC - INC
Program Participants NPVP = BC + INC - PC

IV.B. Assumptions and Inputs

GENERAL ASSUMPTIONS

- Evaluation Horizon – Each evaluation applied SPM methodology, adjusted as described above, for 11 years, ten years in addition to the starting year of 2003

- Discount Rate - Each evaluation used the same discount rate of 9 percent. Though each utility would apply a different discount rate it was agreed that 9 percent was a reasonable simplification.

- Proposal Overlap - The tariff proposals are not mutually exclusive with respect to demand reduction overlap. Indeed, some of the proposals might compete for the same demand reduction from the same customer. The evaluation included no attempt to assess this overlap.

CASE SPECIFIC INPUTS

The SPM based cost evaluation equations described above contain six benefit or cost terms. Inputs for each term require yearly estimates. Each proposer provided yearly inputs based upon their best estimate for each of these terms. In making those estimates, proponents were requested to satisfy the following:

- Bill Changes (BC) – As explained in the section describing adjustments to SPM methodology, proponents were asked to provide total rather than differential bill changes. If the proposal delivers its benefit without changing the tariff then a differential approach delivers accurate information.

- Utility Avoided Costs (UAC) – As explained in the section describing adjustments to SPM methodology, proponents were asked to provide total rather than differential avoided cost changes. In addition, the November 13, 2002 ALJ Ruling specified two sets of avoided costs. Proponents were asked to provide inputs using each set.

Participant costs were also estimated. These cost estimates did not attempt to quantify the value of electricity to the customer, i.e., the opportunity cost of the customer's demand reduction. However, because these are voluntary programs, participants will make their own determinations of total costs and volunteer or not on their own.

Appendix C contains the detailed inputs provided by each proponent for each case proposed.

IV.C. Results

DEMAND REDUCTION

(Note: WG2 urges that these results be interpreted with caution as WG2 recognizes that improvements and further adjustments to the current SPM analyses are needed for this application of the methodology)

These demand reduction amounts were estimated using descriptions from demand reduction proposals and inputs. The line titled **DmdReduc_mWhr** was added to the input worksheets prepared by proponents. It provides the numeric detail of the demand reduction estimate. The following table shows the demand reduction over the hours in which the demand was reduced for each proposal.

TABLE 5: Demand Reduction Amounts

CPA	Program	Dmd Recution mW	hrs Reduced	Dmd Reduction mWh
ACWA	CPP	150.0	36	5400
CPA	CallOp	200.0	100	20000
CPA	NonSpAS	100.0	100	10000
CPA	SupEn	150.0	10	1500
IMS	Trans Pilot	50.0	50	2500
JOINT	CPP	140.0	84	11760
SCE	DBP	30.0	84	2520
PG&E	DBP	14.0	84	1176
SDG&E	DBP	8.0	4	32
SDG&E	HPO	5.9	213	1257

The demand reduction amounts in this table do not sum to a total demand reduction amount because the proposed programs may overlap. For instance, the ACWA CPP, the CPA CallOp and the PG&E RTP/CPP might all be competing for the same demand reduction from the same potential participant.

Also note that for simplicity, these demand reductions were presumed to be the same in each year. In reality, program ramp up would require some time.

AVOIDED COSTS

With one exception, the participants used the following avoided cost rates for calculating avoided costs.

High Avoided Cost Cases			
Technology	Fixed Avoided Costs	Heat Rate	Fuel Cost
New Simple Cycle Gas Turbine	85.00 $/kW-Yr	10,000 BTU/kWh	3.50 $/mmBTU
Low Avoided Cost Cases			
Existing Peaker	10.00 $/kW-Yr	20,000 BTU/kWh	3.50 $/mmBTU

The exception was the IMServ Transmission Pilot. Avoided costs in this pilot presumed fixed avoided of the amounts shown above plus 20.00 $/kW-yr. This additional amount was included as and adjustment for system operation in congested areas.

RESULTS OF TOTAL RESOURCE COST TEST

NPVTRC = UAC – PRC - PCN

NPVBCR = UAC/(PRC + PCN)

NPVTRC/mWh = NPVTRC/(11 X Dmd Reduction mWh)

High Avoided Cost Case

Proposer	Program	NPV($1000)	Benefits/Costs	NPV/MWh
ACWA	CPP	$92,410	26.91	1.56
CPA	CallOp	$69,594	2.13	0.32
CPA	NonSpAS	$45,762	2.32	0.42
CPA	SupEn	$52,585	2.24	3.19
IMS	TransPilot	$21,756	2.22	0.79
JOINT	CPP	$73,320	5.15	0.57
PG&E	DBP	$7,957	9.12	0.62
SCE	DBP	$18,286	15.25	0.66
SDG&E	DBP	$4,981	79.90	14.15
SDG&E	HPO	$2,344	4.84	0.17

Low Avoided Cost Case

Proposer	Program	NPV($1000)	Benefits/Costs	NPV/MWh
ACWA	CPP	$10,363	3.91	0.17
CPA	CallOp	-$36,478	0.41	-0.17
CPA	NonSpAS	-$7,275	0.79	-0.07
CPA	SupEn	-$30,474	0.28	-1.85
IMS	TransPilot	-$5,411	0.70	-0.20
JOINT	CPP	-$1,245	0.93	-0.01
PG&E	DBP	$634	1.65	0.05
SCE	DBP	$2,250	2.75	0.08
SDG&E	DBP	$530	9.40	1.51
SDG&E	HPO	-$263	0.57	-0.02

These results show that from a total resource perspective, each high avoided cost case yields a net benefit.

RESULTS OF PARTICIPANT TEST

NPVP = BC + INC - PC

NPVPBCR = (BC + INC)/PC

NPVP/mWh = NPVP/(11 X Dmd Reduction mWh)

High Avoided Cost Case

Proposer	Program	NPV($1000)	Benefits/Costs	NPV/MWh
ACWA	CPP	$51,796	4.45	0.87
CPA	CallOp	$59,726	3.40	0.27
CPA	NonSpAS	$39,248	3.93	0.36
CPA	SupEn	$27,882	2.50	1.69
IMS	TransPilot	$16,600	3.67	0.60
JOINT	CPP	$51,585	4.70	0.40
PG&E	DBP	-$90	0.93	-0.01
SCE	DBP	-$196	0.93	-0.01
SDG&E	DBP	$65	4.48	0.18
SDG&E	HPO	$1,150	1.57	0.08

Low Avoided Cost Case

Proposer	Program	NPV($1000)	Benefits/Costs	NPV/MWh
ACWA	CPP	$51,796	4.45	0.87
CPA	CallOp	$59,726	3.40	0.27
CPA	NonSpAS	$39,248	3.93	0.36
CPA	SupEn	$27,882	2.50	1.69
IMS	TransPilot	$16,600	3.67	0.60
JOINT	CPP	$51,585	4.70	0.40
PG&E	DBP	-$90	0.93	-0.01
SCE	DBP	-$196	0.93	-0.01
SDG&E	DBP	$65	4.48	0.18
SDG&E	HPO	$1,150	1.57	0.08

The Participant Test includes no consideration of avoided costs. Hence the High and Low Avoided Cost Cases yield the same result.

Also note that this test may not fully reflect the value of electricity to customers.

From a participant perspective, this shows that most proposals yield positive results.

RESULTS OF RATEPAYER IMPACT MEASURE TEST

NPVRIM = UAC – BC – PRC - INC

BRCRIM = UAC/(BC + PRC + INC)

NPVRIM/mWh = NPVRIM/(11 X Dmd Reduction mWh)

High Avoided Cost Case

Proposer	Program	NPV($1000)	Benefits/Costs	NPV/MWh
ACWA	CPP	$25,614	1.36	0.43
CPA	CallOp	$9,868	1.08	0.04
CPA	NonSpAS	$6,514	1.09	0.06
CPA	SupEn	$24,703	1.35	1.50
IMS	TransPilot	$5,156	1.15	0.19
JOINT	CPP	$7,785	1.09	0.06
PG&E	DBP	$6,676	3.95	0.52
SCE	DBP	$15,482	4.79	0.56
SDG&E	DBP	$4,898	34.50	13.91
SDG&E	HPO	-$816	0.78	-0.06

Low Avoided Cost Case

Proposer	Program	NPV($1000)	Benefits/Costs	NPV/MWh
ACWA	CPP	-$56,433	0.20	-0.95
CPA	CallOp	-$96,204	0.21	-0.44
CPA	NonSpAS	-$46,522	0.37	-0.42
CPA	SupEn	-$58,356	0.17	-3.54
IMS	TransPilot	-$22,011	0.36	-0.80
JOINT	CPP	-$66,780	0.20	-0.52
PG&E	DBP	-$647	0.71	-0.05
SCE	DBP	-$554	0.86	-0.02
SDG&E	DBP	$447	4.06	1.27
SDG&E	HPO	-$3,423	0.09	-0.25

This shows that ratepayers other than participants will yield a positive or negative net benefit depending upon the proposed program.

IV.D. Issues for Cost-Effectiveness Analyses

First, the August 26th meeting of Working Group 1 devoted considerable time to the difference between the "resource planning" approach and the "economist's" or "price-it-right" approach. During the course of that meeting a consensus agreement emerged for a "preference for a blended and iterative approach to setting quantitative goals, combining resource planning and 'price-it-right' elements" (ALJ ruling, 9/5/02, p.6). At least one party has strongly argued (and a number of parties have shown sympathy for) that a more appropriate approach historically for a benefit/cost analysis under the 'price-it-right' perspective is the standard social welfare (i.e., net societal benefit) formulation[41]:

$$\Delta \text{ social welfare} = -\tfrac{1}{2}\, \Delta P_1\, \Delta Q_1 - \tfrac{1}{2}\, \Delta P_2\, \Delta Q_2$$ [42]

Such welfare analysis is usually developed using customer demand elasticity information. Much of the historical data on elasticities is based on situations with modest variations in prices. There is less experience with very big changes in price – for example, 1200% increase from $.25/kWh to $3.00/kWh.

Other parties have said that other items identified in the ALJ rulings have not been adequately captured in this Standard Practice analysis. For example, none of the following benefits identified in ALJ ruling of 10/2/02 (p. 9) have been captured:

- Avoided T&D upgrade costs,
- Benefit of any net reduction in air emissions (and other environmental externalities)
- Value to customers of more timely and accurate information about electricity use).

Moreover, the ALJ ruling of 11/13/02 stated (p. 3) that " a complete cost-benefit analysis … should include environmental value (criteria pollutant emissions and air quality impacts, land/water use impacts, greenhouse emissions, etc.), insurance/reliability value, market effects, fuel price stability and other criteria that are more difficult to quantify".

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[41] See for example: Acton, Jan Paul and Bridger M. Mitchell, Welfare Analysis of Electricity Rate Changes, Rand Note N-2010-HF/FF/NSF, May 1983; and Borenstein, Severin, Michael Jaske, and Arthur Rosenfeld, Dynamic Pricing, Advanced Metering and Demand Response in Electricity Markets, University of California Energy Institute, Center for the Study of Energy Markets, Working Paper CSEM WP 105, October 2002.

[42] This formula measures the increase in social welfare (net societal benefit) associated with a move from a uniform average electricity price to time differentiated marginal cost pricing. The ΔP's are the change in prices in each separate pricing period, and the ΔQ's are the corresponding change in customer usage in response to the price change.

Another issue concerned the characterization of distributional impacts of demand response programs. In DSM programs, "free riders" (e.g., customers who receive a rebate or incentive to participate in a program activity or appliance purchase that they would undertake even without a financial inducement) are generally considered to reduce program cost effectiveness. The issue is more complicated in evaluating demand response programs. For instance, introducing a voluntary time-of-use rate option allows predominantly off-peak users to receive a lower overall bill without any change in behavior. However, this is arguably still an improvement, since it results in a more equitable allocation of costs across different customers.

There is uncertainty regarding the costs that demand reduction programs are able to avoid as a result of market structure and utility procurement changes. Currently, California electricity markets are based predominantly on a single market-clearing price for electricity that reflects both energy and capacity (scarcity) value.[43] As a result, at peak times the price of electricity can rise sharply (within the constraints of whatever market price cap is imposed), reflecting scarcity payments to owners of capacity. It is these high payments that encourage construction of new capacity by market participants, and provide a visible price signal to customers (through the operation of demand response programs).

The development of some form of capacity obligation is under active discussion at both the state and federal level. A capacity obligation would require load service entities to separately procure capacity resources to cover an amount of load in excess of forecasted requirements (e.g., 112% of expected summer peak demand). This would create a separate capacity market, which would most likely not have visible hourly prices. A similar effect could also result from utility procurement activities. Fully procuring future requirements could result in removing capacity-related prices from the spot market. The impact of this kind of change in market structure on the various demand response programs under consideration in this proceeding has not been assessed.

Many of Working Group 2 believe these issues should be addressed in Phase 2 of this Proceeding as focus on Demand Responsiveness beyond programs/pilots for the summer of 2003 is brought to bear.

[43] Ancillary services are priced separately, but constitute a minor component of the overall electricity market.

APPENDIX A
Working Group 2
January 10, 2002 Meeting Minutes

Seven handouts were provided: meeting agenda, SCE Advanced Metering OIR Research Focus Groups Preliminary Report (SCE), Customer Incentives and Risk Management Proposal (CCEA), Draft Comments of the City and County of SF Addressing WG 2 Reports (CCSF), Cost Effectiveness Update (S. Anderson), CPA Demand Reserves Partnership Status Update (J. Flory), Draft Report Outline (M. Jaske).

Mike Jaske briefly explained the circumstances which led to the call for this meeting, e.g. the decision by UDCs to respond to the feedback from WG1 that the initial round of proposals seemingly neglected too many of the recipients of the AB29x RTP metering systems, and thus to file a new CPP proposal and withdraw some others.

I. Review of New UDC Tariff Proposal

A. Bell summarized the UDC's new tariff proposal, which was distributed to WG 2 on December 30. Several clarification questions were asked and responded to:

> Q: Specific rates were missing from UDC proposal.
> A: The UDCs did not have the time to re-calculate the affected rates, but did provide references as to those rate schedules that would be affected. Parties can calculate CPP on-peak and partial peaks rates based on the parameters described in the proposal. Each UDC will file advice letters with the specific rates if the Commission approves the proposal.
>
> Q: The UDC proposal states that on-peak and partial peak rates on non-CPP operating days would be discounted. How large is the discount?
> A: The discount is estimated at 20%. The CEC has done some preliminary analysis of rate impacts for customers using several load profiles to best understand the implication of the CPP tariff.
>
> Q: Why is the new proposal more attractive to customers with large air conditioning loads?
> A: By defining the peak as 3 pm to 6 pm (as opposed to noon to 6 pm), the customers are better able to respond to CPP, and still keep their buildings relatively comfortable using pre-cooling measures.
>
> Q: The UDC proposal estimates a 15% participation rate and a 15% demand response. How were these percentages developed?
> A: The percentages for both participation and demand response have no specific analysis to support them, but are the UDC's estimates and are admittedly optimistic.
>
> Q: Did the UDCs consider system load as a trigger rather than temperature?

A: The UDCs prefer temperature as a trigger as it is more easily accessible, and easier for customers to understand. Also system load and temperature are highly correlated, so the proposal would essentially be addressing high load conditions.

Q: What happens if the summer is cooler than normal?

A. The UDCs could ratchet the temperature triggers down so that the program is operated as close to its maximum (15 CPP days) as possible.

Q. Are demand charge rates affected by the new proposal?

A. No. However if a participating customer reduces its demand on CPP days, then the customer will likely see a reduction in the demand charge portion of their bill since there is a strong correlation between the maximum demand of a customer in month and the periods of high energy use.

Q: Are agricultural customers allowed to participate?

A: No. The UDCs foresee several administrative challenges if ag. customers are included, and many of these customers have not received the meters necessary to participate.

C. King (CCEA) summarized a proposed supplement to the UDC's new CPP proposal. The CCEA proposed two options that would help overcome customer reluctance to participate in a new tariff: (A) summer trial period that would allow the customer to receive 90% of the difference between the customer's aggregate CPP bill and the customer's bill on the otherwise applicable tariff; (B) customer receives payment for qualifying demand reduction equipment. Cost caps for both options were also proposed: $1.7 m. for (A), and $7.5 m. for (B). One WG 2 participant noted that Option A's 90% reimbursement should be 100% in order to attract participants, while others noted that a 100% reimbursement enables participants to do nothing. Discussion emerged as to how the costs of either option would be recovered (via balancing accounts) and if there are any leftover AB 970 funds that could possibly fund a portion of Option B. One participant felt that Option A was similar to a 'bait and switch' tactic, since the reimbursement applies only to the first summer. Others wanted to emphasize a "technical assistance" supplement to the CPP tariff (see below).

The City and County of San Francisco (CCSF) summarized their proposal for the UDC's new CPP. CCSF is concerned that the UDC's temperature trigger needs to be customized to address SF's unique summer weather. CCSF also noted that it has a winter peak that is not addressed by the UDC's new proposal. PG&E responded that it will meet with CCSF to find out ways to address their concerns, and that some tweaking could be done to address SF's summer weather. It was less likely that a winter peak component could be added to the proposal, but this could be addressed in a parallel track with the city. CCSF also informed WG 2 that the city is contemplating legislation that would require all buildings in SF to participate on a CPP tariff.

C. Murley (BOMA) raised three general concerns about the UDC's new CPP proposal: (1) many buildings have already invested in energy efficiency equipment or are conserving energy and are thus unable to provide any more demand response; (2) many buildings have lease agreements with their tenants which complicates demand response efforts (comfort expectations by the tenants, complex billing arrangements on energy usage make demand response less rewarding for tenants); (3) the UDC's newest proposal is an improvement over PG&E's initial CPP proposal, but a three hour peak period is still too difficult for many customers to avoid without significant investment in equipment such as thermal energy storage which is very expensive. BOMA anticipates there will be very little interest in the new UDC proposal, at least in SF. Murley noted that these concerns are limited to PG&E customers in San Francisco, and thus it is possible that other PG&E customers (as well as non-PG&E customers) may have different circumstances that enable them to participate. BOMA had no tweaks to suggest for the proposal, as its concerns are more fundamental in nature.

WG 2 participants watched selected video clips of SCE's focus group discussions (from December 2002) regarding demand response programs. In general, the focus groups displayed a lukewarm receptivity to demand response in general, noting that they are already doing as much as they can to reduce demand. The focus groups also seemed to view real-time pricing as unattractive due to uncertainty over prices and complexity in participating. CPP was seen as simpler to understand and easier to use.

WG 2 participants discussed customer education and marketing efforts for the CPP. SCE and PG&E do not anticipate any changes from what was proposed in the December WG 2 report. SDG&E anticipates a slight change in that their C/E and marketing effort will be expanded to include customers who exceed 50 kW.

Finally, WG 2 also discussed the idea of providing customers "technical assistance" as a supplement to the M&CE effort. Potential customers could be educated about the load reduction bendfits and costs of specific technical improvements they could make in their building so that a demand response tariff or program would work for them. The UDCs noted that they are not positioned to have a technical assistance team assembled by June 1, but could develop such a team in the future. There was some discussion of the fact that the CEC had funded Xenergy to provide technical assistance of this same typo as part of the State's efforts in 2001 to reduce demand in commercial buildings. C. King agreed to pursue obtaining a description of this effort that could be included in the Addendum report.

S. Anderson provided a summary of the revised cost-effectiveness tests using the new UDC proposal, and also combining the UDC's Demand Bidding Program. The new UDC proposal passed the both the high and low-avoided costs cases for the Participant Test, passed the high avoided cost case and failed the low-avoided costs case for the Ratepayer Impact Test, and passed both cases for the Total Resource Cost Test. Because SCE is withdrawing its modified DBP, Anderson was directed to redo the summary of the C/E test results by separating the remaining two DBP programs (PG&E and SDG&E) and dropping the SCE results.

II. Review of CPA DRP vis-à-vis UDC Demand Bidding

J. Flory (CPA) made a presentation that provided a status update on the CPA's Demand Reserves Program (DRP) in light of the Commission's removal of $29 million from DWR's revenue requirement (D.02-12-045). DWR is appealing the Commission's decision. Flory also did a comparative summary between DRP and DBP demonstrating how the two programs are similar and different. Flory informed WG 2 that there are two modifications planned for DRP: an enhanced marketing effort using The Energy Coalition, and adding a fourth summer month capacity payment. These modifications amount to approximately an additional $5.5 million to program costs. Finally, Flory proposed that participants on the DRP be allowed to participate in multiple demand response programs. Some WG 2 participants expressed concern that multiple participation could reward customers twice for the same curtailed MWs, which would not be cost-effective. Flory noted that there are ways to design capacity/energy payments so that 'double-dipping' can be avoided. WG 2 agreed that the CPA's DRP will need to have its cost-effectiveness test results re-done using the new costs, as well as having outputs for DRP combined with the new CPP proposal (multiple participation).

SCE also clarified that it proposes to withdraw its Demand Bidding Program. SCE now believes that a price trigger for the DBP will not be ready during summer 2003, and it is concentrating its effort on the CPP tariff. If a viable price trigger from a market emerges, SCE will be ready to modify the DBP as it proposed earlier. SDG&E and PG&E are willing to retain the price trigger modification within the DBP for their service areas, even though they do not expect the conditions to operate the program are likely to exist in summer 2003. Essentially, SDG&E and PG&E seek advance approval for this change speculating that the market will develop as the CAISO has promised and SCE will delay the approval process for this change until the market conditions justifying it have transpired.

III. Discussion of Remaining Options

WG 2 participants had nothing to discuss for this topic.

IV. Next Steps in Phase 1 for >200 kW Activities

M. Jaske informed WG 2 that a supplemental report is needed to document the new UDC CPP proposal as well as the other changes that have occurred post-December 13. WG 2 agreed to divide up responsibility for writing the report (details provided in the attached draft report outline). WG 2 agreed to target Thursday, January 16 as the release date for the report. To make that deadline, the chapter writers must circulate their drafts by close-of-business, Tuesday, January 14. D. Hungerford of the CEC will merge the chapters together into a comprehensive draft for circulation back to WG 2 on Wednesday, January 15. All participants must submit final corrections/edits by noon Thursday, January 16.

WG 2 participants agreed that given the time frame to complete the report, alternative viewpoints will not be incorporated into the report, but be submitted in participants' comments on the report. The report's Introduction and Executive Summary will have text that explains why there are no alternative viewpoints in the report even though this meeting makes clear that such alternative viewpoints exist and are likely to be expressed in Comments filed on the entire WG2 package of reports. Comments on the supplemental report (and the first two WG 2 reports as modified by the errata report dated December 23) will be due 10 days from the supplemental reports release (January 27).

WG 2 participants agreed that the following topics would be re-submitted as entire chapters that replace previous chapters in the first two reports:

(1) Joint UDC CPP Tariff
(2) CPA Demand Reserves Program
(3) Cost-Effectiveness Analysis
(4) Cost Recovery

V. Next Steps in Phase 2 for >200 kW Activities

WG 2 participants discussed the need to organize sub-committees for the Two-Part RTP process and development of the Monitoring and Evaluation Plan. It was anticipated that meetings for both items would not begin until February to follow the submission of comments on the WG2 reports.

Appendix B
List of Authors

Report Section/Subsection	Author	Agency/Company
Executive Summary	B. Kaneshiro	CPUC
I. Introduction		
A. Mission for >200 kW Customers	M. Jaske	CEC
B. Nature of the Working Group Process	“	“
C. Role of this Report	“	“
II. Modifications to Proposals		
A. Withdrawal of Prior Proposals		
SCE Modifications to Proposals	L. Low	SCE
PG&E Withdrawal of RTP/CPP Proposal	A. Bell	PG&E
B. Joint UDC CPP Tariff	A. Bell	PG&E
(1) General Description	“	“
(2) Eligibility	“	“
(3) Source of Drivers/Triggers	“	“
(4) Intended Level of Participation	“	“
(5) Sources/Levels of Cost	“	“
(6) Method of Cost Recovery	“	“
(7) Linkage to Procurement Activities	“	“
(8) Estimated Start Date	“	“
(9) Proposed Method of Implementation	“	“
(10) Lead Time from Approval	“	“
(11) Other Implementation Issues	“	“
C. CPA DRP Proposal	J. Flory	CPA
D. Other Revised Proposals		
(1) Incentives and Risk Management	C. King	CCEA
(2) Multiple Participation	J. Flory	CPA
(3) Withdrawal of Obsolete Tariff	A.Bell	PG&E
III. Modifications to Implementation Activities		
A. Marketing & Customer Education		
PG&E – CPP and DBP	E. Wong	PG&E
SCE - CPP	L. Low	SCE
SDG&E - CPP	S. Sides	SDG&E
CPA DRP	J. Flory	CPA
B. Cost Recovery	C. Blunt	CCEA
IV. Cost Effectiveness Analysis	S. Anderson	Power Value, Inc.
APPENDICES		
A. Meeting Minutes	B. Kaneshiro	CPUC
B. List of Authors	B. Kaneshiro	CPUC
C. Cost Effectiveness Equations/Inputs	S. Anderson	Power Value, Inc.

Appendix C
Cost Effectiveness Equations and Inputs

This appendix replaces Appendix D in the December 13, 2002 WG2 Report.

EQUATIONS USED FOR COST EVALUATION

Total Resource Cost Tests Equations

NPVTRC = BTRC - CTRC

BCRTRC = BTRC/CTRC

Where

$$BRTC = \sum_{t=1}^{N} \frac{UAC_t}{(1+d)^{t-1}}$$

$$CRTC = \sum_{t=1}^{N} \frac{PRC_t + PCN_t}{(1+d)^{t-1}}$$

Participant Tests Equations

NPVP = BP - CP

BCRPVP = BP/CP

Where

$$BP = \sum_{t=1}^{N} \frac{BC_t + INC_t}{(1+d)^{t-1}}$$

$$CP = \sum_{t=1}^{N} \frac{PC_t}{(1+d)^{t-1}}$$

Ratepayer Impact Measure Test Equations

NPVRIM = BRIM - CRIM

BCRRIM = BRIM/CRIM

Where

$$BRIM = \sum_{t=1}^{N} \frac{UAC_t}{(1+d)^{t-1}}$$

$$CRIM = \sum_{t=1}^{N} \frac{BC_t + PRC_t + INC_t}{(1+d)^{t-1}}$$

INPUTS

Cost Effectiveness Equation Inputs
Sheet 1 of 7

Proposer	Program	Start Year	Financial Discount Rate	DmdReduc_mWhr
ACWA	CPP	2003	0.09	5400
CPA	CallOp	2003	0.09	20000
CPA	NonSpAS	2003	0.09	10000
CPA	SupEn	2003	0.09	1500
IMS	TransPilot	2003	0.09	2500
JOINT	CPP	2003	0.09	11760
PG&E	DBP	2003	0.09	1176
SCE	DBP	2003	0.09	2520
SDG&E	DBP	2003	0.09	32
SDG&E	HPO	2003	0.09	1257
ACWA	CPP	2003	0.09	5400
CPA	CallOp	2003	0.09	20000
CPA	NonSpAS	2003	0.09	10000
CPA	SupEn	2003	0.09	1500
IMS	TransPilot	2003	0.09	2500
JOINT	CPP	2003	0.09	11760
PG&E	DBP	2003	0.09	1176
SCE	DBP	2003	0.09	2520
SDG&E	DBP	2003	0.09	32
SDG&E	HPO	2003	0.09	1257

Cost Effectiveness Equation Inputs
Sheet 2 of 7

Proposer	Program	BCt1	BCt2	BCt3	BCt4	BCt5	BCt6	BCt7	BCt8	BCt9	BCt10	BCt11
ACWA	CPP	$3,855	$3,855	$3,855	$3,855	$3,855	$3,855	$3,855	$3,855	$3,855	$3,855	$3,855
CPA	CallOp	$3,600	$3,600	$3,600	$3,600	$3,600	$3,600	$3,600	$3,600	$3,600	$3,600	$3,600
CPA	NonSpAS	$1,800	$1,800	$1,800	$1,800	$1,800	$1,800	$1,800	$1,800	$1,800	$1,800	$1,800
CPA	SupEn	$270	$270	$270	$270	$270	$270	$270	$270	$270	$270	$270
IMS	TransPilot	$450	$450	$450	$450	$450	$450	$450	$450	$450	$450	$450
JOINT	CPP	$6,975	$6,975	$6,975	$6,975	$6,975	$6,975	$6,975	$6,975	$6,975	$6,975	$6,975
PG&E	DBP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SCE	DBP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SDG&E	DBP	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3
SDG&E	HPO	$426	$426	$426	$426	$426	$426	$426	$426	$426	$426	$426
ACWA	CPP	$3,855	$3,855	$3,855	$3,855	$3,855	$3,855	$3,855	$3,855	$3,855	$3,855	$3,855
CPA	CallOp	$3,600	$3,600	$3,600	$3,600	$3,600	$3,600	$3,600	$3,600	$3,600	$3,600	$3,600
CPA	NonSpAS	$1,800	$1,800	$1,800	$1,800	$1,800	$1,800	$1,800	$1,800	$1,800	$1,800	$1,800
CPA	SupEn	$270	$270	$270	$270	$270	$270	$270	$270	$270	$270	$270
IMS	TransPilot	$450	$450	$450	$450	$450	$450	$450	$450	$450	$450	$450
JOINT	CPP	$6,975	$6,975	$6,975	$6,975	$6,975	$6,975	$6,975	$6,975	$6,975	$6,975	$6,975
PG&E	DBP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SCE	DBP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SDG&E	DBP	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3
SDG&E	HPO	$426	$426	$426	$426	$426	$426	$426	$426	$426	$426	$426

Cost Effectiveness Equation Inputs
Sheet 3 of 7

Proposer	Program	INCt1	INCt2	INCt3	INCt4	INCt5	INCt6	INCt7	INCt8	INCt9	INCt10	INCt11
ACWA	CPP	$5,150	$5,150	$5,150	$5,150	$5,150	$5,150	$5,150	$5,150	$5,150	$5,150	$5,150
CPA	CallOp	$7,800	$7,800	$7,800	$7,800	$7,800	$7,800	$7,800	$7,800	$7,800	$7,800	$7,800
CPA	NonSpAS	$5,300	$5,300	$5,300	$5,300	$5,300	$5,300	$5,300	$5,300	$5,300	$5,300	$5,300
CPA	SupEn	$6,000	$6,000	$6,000	$6,000	$6,000	$6,000	$6,000	$6,000	$6,000	$6,000	$6,000
IMS	TransPilot	$2,625	$2,625	$2,625	$2,625	$2,625	$2,625	$2,625	$2,625	$2,625	$2,625	$2,625
JOINT	CPP	$1,860	$1,860	$1,860	$1,860	$1,860	$1,860	$1,860	$1,860	$1,860	$1,860	$1,860
PG&E	DBP	$173	$173	$173	$173	$173	$173	$173	$173	$173	$173	$173
SCE	DBP	$378	$378	$378	$378	$378	$378	$378	$378	$378	$378	$378
SDG&E	DBP	$8	$8	$8	$8	$8	$8	$8	$8	$8	$8	$8
SDG&E	HPO	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ACWA	CPP	$5,150	$5,150	$5,150	$5,150	$5,150	$5,150	$5,150	$5,150	$5,150	$5,150	$5,150
CPA	CallOp	$7,800	$7,800	$7,800	$7,800	$7,800	$7,800	$7,800	$7,800	$7,800	$7,800	$7,800
CPA	NonSpAS	$5,300	$5,300	$5,300	$5,300	$5,300	$5,300	$5,300	$5,300	$5,300	$5,300	$5,300
CPA	SupEn	$6,000	$6,000	$6,000	$6,000	$6,000	$6,000	$6,000	$6,000	$6,000	$6,000	$6,000
IMS	TransPilot	$2,625	$2,625	$2,625	$2,625	$2,625	$2,625	$2,625	$2,625	$2,625	$2,625	$2,625
JOINT	CPP	$1,860	$1,860	$1,860	$1,860	$1,860	$1,860	$1,860	$1,860	$1,860	$1,860	$1,860
PG&E	DBP	$173	$173	$173	$173	$173	$173	$173	$173	$173	$173	$173
SCE	DBP	$378	$378	$378	$378	$378	$378	$378	$378	$378	$378	$378
SDG&E	DBP	$8	$8	$8	$8	$8	$8	$8	$8	$8	$8	$8
SDG&E	HPO	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Cost Effectiveness Equation Inputs
Sheet 4 of 7

Proposer	Program	PCt1	PCt2	PCt3	PCt4	PCt5	PCt6	PCt7	PCt8	PCt9	PCt10	PCt11
ACWA	CPP	$15,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
CPA	CallOp	$12,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000
CPA	NonSpAS	$7,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000
CPA	SupEn	$9,000	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500
IMS	TransPilot	$3,000	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500
JOINT	CPP	$13,950	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PG&E	DBP	$1,370	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SCE	DBP	$3,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SDG&E	DBP	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3
SDG&E	HPO	$271	$271	$271	$271	$271	$271	$271	$271	$271	$271	$271
ACWA	CPP	$15,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
CPA	CallOp	$12,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000
CPA	NonSpAS	$7,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000
CPA	SupEn	$9,000	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500
IMS	TransPilot	$3,000	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500
JOINT	CPP	$13,950	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PG&E	DBP	$1,370	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SCE	DBP	$3,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SDG&E	DBP	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3	$3
SDG&E	HPO	$271	$271	$271	$271	$271	$271	$271	$271	$271	$271	$271

Cost Effectiveness Equation Inputs
Sheet 5 of 7

Proposer	Program	PRCt1	PRCt2	PRCt3	PRCt4	PRCt5	PRCt6	PRCt7	PRCt8	PRCt9	PRCt10	PRCt11
ACWA	CPP	$1,000	$400	$400	$400	$400	$400	$400	$400	$400	$400	$400
CPA	CallOp	$6,700	$4,700	$4,700	$4,700	$4,700	$4,700	$4,700	$4,700	$4,700	$4,700	$4,700
CPA	NonSpAS	$5,900	$2,400	$2,400	$2,400	$2,400	$2,400	$2,400	$2,400	$2,400	$2,400	$2,400
CPA	SupEn	$4,500	$3,000	$3,000	$3,000	$3,000	$3,000	$3,000	$3,000	$3,000	$3,000	$3,000
IMS	TransPilot	$2,000	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500
JOINT	CPP	$4,200	$2,100	$2,100	$2,100	$2,100	$2,100	$2,100	$2,100	$2,100	$2,100	$2,100
PG&E	DBP	$274	$110	$110	$110	$110	$110	$110	$110	$110	$110	$110
SCE	DBP	$514	$120	$120	$120	$120	$120	$120	$120	$120	$120	$120
SDG&E	DBP	$15	$8	$8	$8	$8	$8	$8	$8	$8	$8	$8
SDG&E	HPO	$290	$50	$50	$50	$50	$50	$50	$50	$50	$50	$50
ACWA	CPP	$1,000	$400	$400	$400	$400	$400	$400	$400	$400	$400	$400
CPA	CallOp	$6,700	$4,700	$4,700	$4,700	$4,700	$4,700	$4,700	$4,700	$4,700	$4,700	$4,700
CPA	NonSpAS	$5,900	$2,400	$2,400	$2,400	$2,400	$2,400	$2,400	$2,400	$2,400	$2,400	$2,400
CPA	SupEn	$4,500	$3,000	$3,000	$3,000	$3,000	$3,000	$3,000	$3,000	$3,000	$3,000	$3,000
IMS	TransPilot	$2,000	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500
JOINT	CPP	$4,200	$2,100	$2,100	$2,100	$2,100	$2,100	$2,100	$2,100	$2,100	$2,100	$2,100
PG&E	DBP	$274	$110	$110	$110	$110	$110	$110	$110	$110	$110	$110
SCE	DBP	$514	$120	$120	$120	$120	$120	$120	$120	$120	$120	$120
SDG&E	DBP	$15	$8	$8	$8	$8	$8	$8	$8	$8	$8	$8
SDG&E	HPO	$290	$50	$50	$50	$50	$50	$50	$50	$50	$50	$50

Cost Effectiveness Equation Inputs
Sheet 6 of 7

Proposer	Program	PCNt1	PCNt2	PCNt3	PCNt4	PCNt5	PCNt6	PCNt7	PCNt8	PCNt9	PCNt10	PCNt11
ACWA	CPP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
CPA	CallOp	$12,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000
CPA	NonSpAS	$7,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000
CPA	SupEn	$9,000	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500
IMS	TransPilot	$3,000	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500
JOINT	CPP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PG&E	DBP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SCE	DBP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SDG&E	DBP	$0										
SDG&E	HPO	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ACWA	CPP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
CPA	CallOp	$12,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000
CPA	NonSpAS	$7,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000
CPA	SupEn	$9,000	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500	$1,500
IMS	TransPilot	$3,000	$500	$500	$500	$500	$500	$500	$500	$500	$500	$500
JOINT	CPP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PG&E	DBP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SCE	DBP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
SDG&E	DBP	$0										
SDG&E	HPO	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Cost Effectiveness Equation Inputs
Sheet 7 of 7

Proposer	Program	UACt1	UACT2	UACt3	UACt4	UACt5	UACt6	UACt7	UACt8	UACt9	UACt10	UACt11
ACWA	**CPP**	$12,939	$12,939	$12,939	$12,939	$12,939	$12,939	$12,939	$12,939	$12,939	$12,939	$12,939
CPA	**CallOp**	$17,700	$17,700	$17,700	$17,700	$17,700	$17,700	$17,700	$17,700	$17,700	$17,700	$17,700
CPA	**NonSpAS**	$10,850	$10,850	$10,850	$10,850	$10,850	$10,850	$10,850	$10,850	$10,850	$10,850	$10,850
CPA	**SupEn**	$12,803	$12,803	$12,803	$12,803	$12,803	$12,803	$12,803	$12,803	$12,803	$12,803	$12,803
IMS	**TransPilot**	$5,338	$5,338	$5,338	$5,338	$5,338	$5,338	$5,338	$5,338	$5,338	$5,338	$5,338
JOINT	**CPP**	$12,268	$12,268	$12,268	$12,268	$12,268	$12,268	$12,268	$12,268	$12,268	$12,268	$12,268
PG&E	**DBP**	$1,205	$1,205	$1,205	$1,205	$1,205	$1,205	$1,205	$1,205	$1,205	$1,205	$1,205
SCE	**DBP**	$2,638	$2,638	$2,638	$2,638	$2,638	$2,638	$2,638	$2,638	$2,638	$2,638	$2,638
SDG&E	**DBP**	$680	$680	$680	$680	$680	$680	$680	$680	$680	$680	$680
SDG&E	**HPO**	$398	$398	$398	$398	$398	$398	$398	$398	$398	$398	$398
ACWA	**CPP**	$1,878	$1,878	$1,878	$1,878	$1,878	$1,878	$1,878	$1,878	$1,878	$1,878	$1,878
CPA	**CallOp**	$3,400	$3,400	$3,400	$3,400	$3,400	$3,400	$3,400	$3,400	$3,400	$3,400	$3,400
CPA	**NonSpAS**	$3,700	$3,700	$3,700	$3,700	$3,700	$3,700	$3,700	$3,700	$3,700	$3,700	$3,700
CPA	**SupEn**	$1,605	$1,605	$1,605	$1,605	$1,605	$1,605	$1,605	$1,605	$1,605	$1,605	$1,605
IMS	**TransPilot**	$1,675	$1,675	$1,675	$1,675	$1,675	$1,675	$1,675	$1,675	$1,675	$1,675	$1,675
JOINT	**CPP**	$2,215	$2,215	$2,215	$2,215	$2,215	$2,215	$2,215	$2,215	$2,215	$2,215	$2,215
PG&E	**DBP**	$218	$218	$218	$218	$218	$218	$218	$218	$218	$218	$218
SCE	**DBP**	$476	$476	$476	$476	$476	$476	$476	$476	$476	$476	$476
SDG&E	**DBP**	$80	$80	$80	$80	$80	$80	$80	$80	$80	$80	$80
SDG&E	**HPO**	$47	$47	$47	$47	$47	$47	$47	$47	$47	$47	$47